

CALIFORNIA ENERGY COMMISSION

1516 NINTH STREET
SACRAMENTO, CA 95814-5512



DATE: April 20, 2005

TO: Interested Parties

FROM: Connie Bruins, Compliance Project Manager

**SUBJECT: Salton Sea Unit 6 Power Project (02-AFC-2C)
Staff Analysis of Proposed Modifications To
Add a Binary-Cycle Turbine and Increase Generation**

On December 23, 2004, the California Energy Commission received a petition from CE Obsidian Energy, LLC, to amend the Energy Commission Decision for the Salton Sea Unit 6 Power Project.

The 185-megawatt steam-powered geothermal project was certified on December 17, 2003, and is expected to begin construction in the summer of 2005. The facility will be located in the Imperial Valley, approximately 1,000 feet southeast of the southern reach of the Salton Sea, within the unincorporated area of Imperial County, California.

The proposed modifications will allow CE Obsidian Energy, LLC, to add a binary-cycle turbine (Organic Rankine Cycle) to the existing steam turbine to capture dissipated energy. Other modifications include: increasing brine flow, adding one production well and one injection well, increasing the voltage of the transmission lines from 161 kV to 230 kV, extending the southern boundary by 328 feet (adding 20 acres to the project site), and increasing the size of the cooling tower. These and other minor modifications will increase generation from 185 to 215 megawatts, increase operational efficiencies, and enhance the project's economics.

Energy Commission staff reviewed the petition and assessed the impacts of this proposal on environmental quality, public health and safety. Staff prepared new and/or made revisions to existing conditions of certification for air quality; biology; facility design, reliability, efficiency and noise; hazardous materials; transmission line safety and nuisance; and transmission system engineering. It is staff's opinion that with the implementation of revised conditions for these technical areas, the project will remain in compliance with applicable laws, ordinances, regulations, and standards and that the proposed modifications will not result in a significant adverse direct or cumulative impact to the environment (Title 20, California Code of Regulations, Section 1769).

The amendment petition has been posted on the Energy Commission's webpage at www.energy.ca.gov/sitingcases. Staff's analyses are attached for your information and review. Staff's analyses and the order (if the amendment is approved) will also be

Interested Parties

April 15, 2005

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posted on the webpage. Energy Commission staff intends to recommend approval of the petition at the May 11, 2004 Business Meeting of the Energy Commission. If you have comments on this proposed modification, please submit them to me at the address below prior to May 11, 2004:

California Energy Commission
1516 9th Street, MS 2000
Sacramento, CA 95814

Comments may be submitted by fax to (916) 654-3882, or by e-mail to cbruins@energy.state.ca.us. If you have any questions, please contact Connie Bruins, Compliance Project Manager, at (916) 654-4545.

Attachments

**SALTON SEA GEOTHERMAL UNIT #6 (02-AFC-2C)
PETITION TO ADD A BINARY-CYCLE TURBINE AND INCREASE
GENERATION
APRIL 2005**

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**SALTON SEA GEOTHERMAL UNIT #6 (02-AFC-2C)
PETITION TO ADD A BINARY-CYCLE TURBINE AND INCREASE
GENERATION
SUMMARY, CONCLUSION AND STAFF RECOMMENDATION
APRIL 2005**

BACKGROUND

On December 23, 2004, the California Energy Commission received a petition from CE Obsidian Energy, LLC (CEOE) to modify the Salton Sea Unit 6 (SSU6) Project. The 185-megawatt project was certified on December 17, 2003, and is expected to begin construction in the summer of 2005. The facility will be located in the Imperial Valley, approximately 1,000 feet southeast of the southern reach of the Salton Sea, within the unincorporated area of Imperial County, California.

The Salton Sea Unit 6 project was certified employing a triple flash, three-pressure steam turbine generator cycle. At the time of certification this technology represented the most efficient generating technology yet applied to this geothermal resource. However, when the project owner solicited bids from engineering /construction firms, the proposals received recommended certain improvements to the project that would increase generation efficiency and reduce per-kilowatt capital cost. Accordingly, CEOE seeks to amend the project certification to allow incorporation of these improvements.

PROPOSED AMENDMENT

The project owner has discovered, during the review of the Engineering Procurement and Construction (EPC) contract proposals, that several changes in the project design could minimize construction costs, increase operation efficiencies, and enhance the project's economics. After reviewing these proposals, the CEOE decided to incorporate the following project design changes into the SSU6 Project:

- The addition of one production well on well pad OB-2 and one injection well on pad OBI-1 (Pad O) with associated piping sited on existing well pads;
- Increased geothermal brine flow from 12.8 million pounds per hour (pph) to an expected flow of 15.1 million pph to facilitate the production of an additional 20 MW of electrical power;
- Addition of an ORC unit to utilize energy dissipated from the dilution water heater (DWH) to produce up to 10.1 MW;
- Increased net electrical generation from 185 MW to 215 MW as a result of increased brine flow and the addition of the ORC unit;
- Elimination of the two DWH vent stacks, visible plumes, and associated emissions by condensing steam from the dilution water heater in a closed-loop system provided by the ORC unit;
- Addition of an Atmospheric Flash Tank venting system that will only operate an estimated 50 hours per year when the ORC system is not operating;

- Increase the voltage of the electrical transmission lines from 161 kV to 230 kV with no changes to the number, height, or placements of the poles;
- Elimination of one of the two primary and secondary clarifier trains;
- Elimination of one of the two vacuum belt filters;
- Increased cooling tower footprint size and recirculation rate from 260,000 gallons/minute (gpm) to 323,635 gpm in order to support the additional heat rejection needs resulting from the increased plant capacity and ORC unit;
- Utilization of a counter flow cooling tower design as opposed to the cross flow design originally proposed;
- Revision in the distribution of the non-condensable gases and condensate makeup water introduction to more evenly distribute H₂S emissions in the cooling tower, which is being done to enhance cooling tower operation;
- Move the eastern 10-cell cooling tower 60 meters to the west;
- Addition of a 40 foot vent stack to each of the four atmospheric flash tanks for emergency relief only;
- Replacement of the biological H₂S abatement (oxidizer box) with a 91% efficient chemical abatement system, that will control the H₂S in the high pressure steam condensate stream, by using two aeration basins (each 80 feet by 50 feet by 10 feet above grade) near the cooling towers to treat the hotwell condensate with hydrogen peroxide and Tower Brom 991 (or equivalent) prior to delivery to the cooling tower; and
- Extension of the project site's southern boundary by 328 feet (100 meters), increasing the project site by 19.4 acres (2,571 feet by 328 feet) to a total of approximately 100 acres.

Not all of the project design changes affect the air quality analysis for the SSU6 Project. However, several of the design changes would alter the construction and/or operations of the plant thereby changing the air quality emissions.

STAFF ANALYSIS

The petition was reviewed by Energy Commission technical staff for potential environmental effects and consistency with applicable laws, ordinances, regulations and standards (LORS). Many of the proposed project features and potential environmental effects were previously analyzed by staff during their review of the original Salton Sea Unit 6 Geothermal Project Application for Certification. Where applicable, staff referred to those previous environmental assessments in the attached analyses of the binary-cycle petition. Staff determined that the technical areas of cultural resources; geology and paleontology; socioeconomic, soil and water resources; traffic and transportation; visual; waste management; and worker safety and fire protection were not affected by the proposed changes and no revisions or new conditions of certification are needed to ensure that the project remains in compliance with all applicable LORS. Staff determined that the following technical or environmental areas will be affected by the proposed project change to binary-cycle operations and has proposed new and revised conditions of certification in order to assure compliance with LORS and to reduce potential environmental impacts to a level of insignificance.

- **Air Quality** – Construction impacts from the revised proposed design do not change significantly and remain mitigated with the implementation of the existing staff conditions of certification. Operating impacts from the revised project design (increased brine flow, the addition of the ORC unit and increased cooling needs) will be fully mitigated with the recommended revisions to the following conditions of certification:
 1. the Imperial County Air Pollution Control District's (District's) revisions/deletions to 21 conditions (**AQ-4 to AQ-9, AQ-15 to AQ-17, AQ-19 to AQ-23, AQ-26 to AQ-28, AQ-33 to AQ-35, and AQ-37**),
 2. the addition of seven new District conditions (**AQ-39 through AQ-45**),
 3. minor revisions to three staff conditions (**AQ-C11, AQ-C14, and AQ-C15**),
 4. revisions to the verifications of five District conditions (**AQ-4, AQ-5, AQ-15, AQ-21, AQ-23, and AQ-31**), and
 5. two new staff conditions (**AQ-C16 and AQ-C17**).

The project's emission offset mitigation and mitigation compliance demonstration requirements have been revised to address the increased project operating emissions.

- **Biological Resources**— the design changes proposed are fully mitigated with implementation of the existing conditions of certification, with the exception of burrowing owl habitat losses. Staff and the project owner have agreed to revise **BIO-25** to protect additional burrowing owl habitat and thus mitigate the project's larger footprint. The federal lead for the project, the U.S. Army Corps of Engineers determined the design changes proposed in the amendment have the potential to affect federally protected species and their habitat, but revisions to the project's existing Biological Opinion were unnecessary. Since the U.S. Fish and Wildlife Service concurred with this decision, the project owner has all the necessary permits for the project construction and operation. Staff and the project owner have agreed to a procedural change in Condition of Certification **BIO-12**.
- **Facility Design, Reliability, Efficiency and Noise**—the original project certification included 20 Facility Design Conditions of Certification and 8 Noise and Vibration Conditions of Certification. These conditions will provide adequate assurance that the modified project will comply with engineering codes and standards, and will present no adverse noise or vibration impacts beyond those found acceptable in the original proceeding. Staff has modified Facility Design Condition of Certification **GEN-2, Table 1**, to reflect the changes in equipment to be included in the modified project.
- **Hazardous Materials Management**—the addition of the isopentane based power generating cycle will necessitate the storage and handling of about 18,500 gallons of isopentane at the site. Isopentane is a hazardous material that poses a risk of both fire and explosion. These risks are enhanced by the heating of the isopentane to a vapor state in the power generating cycle. The greatest potential issue regarding this amendment is the implications that the additional isopentane cycle will have on fire protection systems at the facility. Staff requested additional clarification regarding fire protection and determined that the new cycle is designed with

extensive integral fire protection systems. In addition the fire protection plan will be amended and sent to the local fire department for review. With timely submittal and acceptance of these plans by the applicable regulatory agencies this facility will pose no significant risks to public health and will remain in compliance with applicable LORS **HAZ-2**.

- **Land Use**—the original project included seven Land Use Conditions of Certification. These conditions will provide adequate assurance that the modified project will comply with the local LORS. With the addition of 20 acres to the project footprint, **LAND-6** has been modified to reflect the increased loss of prime farmland from 96 acres to 116 acres. Staff has also provided an additional condition **LAND-8**, which requires the applicant to provide copies to the CPM of the final decision by Imperial County for the minor modification to the Conditional Use Permit.
- **Transmission System Engineering**—the project as modified by the amendment will have a marginal impact on the electricity grid, but the selected mitigation measures are appropriate to offset the impacts. With one modification to **TSE-5** the conditions will provide adequate assurance that the proposed project, as modified, will remain in compliance with LORS.
- **Transmission Line Safety and Nuisance**—the original project certification included five Conditions of Certification related to Transmission Line Safety and Nuisance. With one modification to **TLSN-1**, the conditions will provide adequate assurance that the proposed higher-voltage transmission will minimize the impacts of concern (aviation safety, interference with radio-frequency communication, audible noise, fire hazards, hazardous shocks, nuisance shocks and electric and magnetic field exposure) to within levels associated with area lines in the 161kV -230 kV voltage class, as identified by California Public Utilities Commission policy.

STAFF CONCLUSION AND RECOMMENDATION

Staff concludes that the following required findings mandated by Title 20, section 1769(a)(3) of the California Code of Regulations can be made and will recommend approval of the petition to the Energy Commission:

- A. There will be no new or additional unmitigated significant environmental impacts associated with the proposed changes,
- B. The facility will remain in compliance with all applicable laws, ordinances, regulations and standards,
- C. The change will be beneficial to the public or project owner. In this case, the amendment will be of benefit to the project owner by improving generation efficiency and reducing per-kilowatt capital cost. Moreover, the change will be beneficial to the State of California by increasing power in an area of need (Southern California).

- D. There has been a substantial change in circumstances since the Commission certification justifying the change. During the review of construction contract proposals, the project owner identified changes in the project design that will augment generation, minimize construction costs, increase operational efficiencies and reduce the overall installed costs of the project.

**SALTON SEA GEOTHERMAL UNIT #6 (02-AFC-2C)
PETITION TO ADD A BINARY-CYCLE TURBINE AND INCREASE
GENERATION
AIR QUALITY ANALYSIS
WILLIAM WALTERS, P.E.
APRIL 2005**

AMENDMENT REQUEST

On December 14, 2004, CalEnergy Obsidian Energy LLC (CEOE or project owner) proposed an amendment to the Salton Sea Unit #6 (SSU6) Project (CEOE 2004). This amendment request seeks to amend CEOE's project design to minimize construction costs, increase operational efficiencies, and reduce the overall installed costs of the project. As a result, the air quality analysis (setting, emissions calculations, and modeling) has been revised, and several of the Conditions of Certification (COCs) and Imperial County Air Pollution Control District (ICAPCD or District) conditions have been requested to be revised accordingly. Additionally, the project owner has requested the revision or deletion of several other COCs not directly related to the changes in the project design.

The project owner is requesting revisions to the following COCs: Air Quality (**AQ-C11**, **AQ-C12**, **AQ-C14**, and **AQ-C15**). The project owner is also requesting revisions to the following District Conditions: **AQ-4** to **AQ-7**, **AQ-15**, **AQ-17**, **AQ-19**, **AQ-20**, **AQ-23**, **AQ-28**, **AQ-31** to **AQ-34**, and **AQ-37**. One new condition, **AQ-39**, was also added by the project owner as a result of the addition of the Organic Rankine Cycle (ORC) unit.

ANALYSIS CONCLUSION

Staff has determined that the requested project design revisions would not cause any significant air quality impacts or revise staff's original conclusions that the project impacts are properly mitigated. The amended project's offset requirements, as required in the COCs, have been adjusted to account for the changes in project emissions. Staff recommends that the requested project design-related revisions to the CEC staff COCs be approved (**AQ-C11**, and **AQ-C14**). Staff does not recommend; the project owner requested deletion of COC **AQ-C12**, the project owner requested deletion of the word "independent" in COC **AQ-C15**, or the project owner requested deletion of California Air Resources Board (CARB) and U.S. Environmental Protection Agency (EPA) in all COC verifications that list those agencies as potential inspecting agencies. However, staff is willing to incorporate the project owner requested addition of the term "certified" to **AQ-C15**.

Staff recommends revisions to the District conditions as provided in the ICAPCD Determination of Compliance (DOC), some of which either do not conform to the project owner's requests, or may change (or add) conditions beyond those identified by the project owner in their amendment request. For example, the District has provided several separate conditions that apply to the new ORC system rather than the single condition recommended by the project owner. The District may revise their conditions

further, based on comments received by the project owner or other parties. The 30-day DOC comment period will end on April 28, 2005. As of this date the District has received no comments. However, any comments received (and need to be addressed), will be included in an addendum to the AQ analysis prior to the Energy Commission's Business Meeting.

The specific staff/ICAPCD recommended version of each of these conditions is provided later in this analysis.

BACKGROUND

In July 2002, CEOE proposed to construct and operate a 185 megawatt (MW) geothermal steam powered electrical generation facility on 80-acres of a 160-acre parcel in the unincorporated area of Imperial County, approximately 1,000 feet southeast of the southern reach of the Salton Sea, 7.5 miles southwest of the town of Niland, and 6.1 miles northwest of the town of Calipatria. The SSU6 Project was certified in December 2003 (CEC 2003c).

The original design of the SSU6 facility consisted of a geothermal resource production facility (RPF), a merchant class geothermal-powered generation facility (PGF), a new 161 kV switchyard, and ancillary facilities including ten geothermal production wells (on five well pads), seven brine injection wells (on three pads), and two electrical transmission lines. The transmission system would consist of two separate lines, totaling 31 miles, connecting the project with separate segments of the Imperial Irrigation District (IID) transmission system. Both lines would be built as 230 kV, but operated at 161 kV. The cooling system would consist of two 10-cell, cross flow design cooling towers. The cooling towers are the primary source of air emissions at the power plant during normal operations. The emissions include the introduced non-condensable gases (NCGs), offgassing from the cooling tower makeup condensate water, and PM10 from liquid drift. NCG emissions would be controlled using a LO-CAT System and hydrogen sulfide (H₂S) polishing system to control H₂S, and a benzene abatement system (carbon absorption unit) to control brine benzene. Condensate emissions would be controlled using biofilter oxidizer cells installed at the condenser inlet end of each of the cooling towers (two total) to control H₂S. Cooling tower particulate matter less than 10 microns (PM10) emissions would be controlled by maintaining the total dissolved solids (TDS) concentration in the circulating water, and by using drift eliminators with an efficiency of 0.0005 percent.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

Laws, Ordinances, Regulations and Standards (LORS) identified in the Energy Commission decision for the SSU6 Project also apply to this amendment request. The project would continue to remain in compliance with all applicable LORS with the requested changes.

SETTING - EXISTING AIR QUALITY

The existing air quality in the project area has been reevaluated since the SSU6 Project was certified. Based on the latest information (November 2004), the project area has been redesignated marginal non-attainment of the federal 8-hour ozone ambient air quality standard (AAQS or standard), serious non-attainment of the federal PM10 standard, and unclassified or attainment of the federal and state PM2.5 standards. Table 1, below, summarizes the federal and state attainment designations for the project area with prior designations from the Final Staff Analysis (FSA) shown in parentheses.

Table 1
Federal and State Attainment Status for the Salton Sea Air Basin ^a

Pollutants	Federal Classification	State Classification
1- hour Ozone	Transitional Non-Attainment ^b	Moderate Non-Attainment
8-hour Ozone	Marginal Non-Attainment (---)	---
PM10	Serious Non-Attainment ^c (Moderate Non-Attainment)	Non-Attainment
CO	Attainment	Unclassified
NO ₂	Attainment	Attainment
SO ₂	Attainment	Attainment
H ₂ S	---	Unclassified
PM2.5	Unclassified/Attainment (---)	Unclassified (---)

Source: CEC 2003a - FSA Part 1, Air Quality Table 2. USEPA 2005. CARB 2005a.

Note(s):

- Prior attainment designations that were in affect at the time of the original licensing of this project, if different from current attainment designations, are provided in parenthesis.
- Clean Air Act Section 185A (Previously called Transitional) areas were designated as an ozone nonattainment area as of the date of enactment of the Clean Air Act Amendments of 1990, and have not violated the national primary ambient air quality standard for ozone for the 36-month period commencing on January 1, 1987, and ending on December 31, 1989. Twelve areas were classified transitional in 1991. Prior Designation retained by operation of Law, but without measured violations.
- Reclassified from Moderate to Serious Non-Attainment on 8/11/2004 (USEPA 2005).

Since the original licensing, additional ambient data has become available. Using the same methodology as used in the FSA the following revisions to background concentrations have been made (CARB 2002, 2005b):

- 24-hour PM10 – 129 ug/m³ from 2003 (formerly 115 ug/m³ from 2000)
- 1-hour CO – 18,560 ug/m³ from 2001 (formerly 8,000 ug/m³ from 1998)
- 8-hour CO – 8,282 ug/m³ from 2001 (formerly 4,000 ug/m³ from 1998)
- Annual NO₂ – 25 ug/m³ from 2004 (formerly 19 ug/m³ from 2002)
- 24-hour SO₂ – 5 ug/m³ from 2001 (formerly 47 ug/m³ from 1999)
- Annual SO₂ – 3 ug/m³ from 2001 (formerly 5 ug/m³ from 1999)

The other background concentrations given in the FSA did not need to be changed in order to conform to the staff's background selection methodology. The PM2.5 ambient air quality attainment status has now been finalized; however, staff has not been able to

determine adequate background ambient air quality data for use in the impact analysis that confirms the attainment status shown on Table 1.

While staff has made these revisions to the background concentrations it should be noted that the high PM₁₀ value is probably a wind related event and the high CO values are very conservative for the project site, which is much farther from the Mexican border than the CO monitoring station.

PROJECT DESCRIPTION CHANGES

The project owner has discovered, during the review of the Engineering Procurement and Construction (EPC) contract proposals, that several changes in the project design could minimize construction costs, increase operation efficiencies, and enhance the project's economics. After reviewing these proposals, the CEOE decided to incorporate the following project design changes into the SSU6 Project:

- The addition of one production well on well pad OB-2 and one injection well on pad OBI-1 (Pad O) with associated piping sited on existing well pads;
- Increased geothermal brine flow from 12.8 million pounds per hour (pph) to an expected flow of 15.1 million pph to facilitate the production of an additional 20 MW of electrical power;
- Addition of an ORC unit to utilize energy dissipated from the dilution water heater (DWH) to produce up to 10.1 MW;
- Increased net electrical generation from 185 MW to 215 MW as a result of increased brine flow and the addition of the ORC unit;
- Elimination of the two DWH vent stacks, visible plumes, and associated emissions by condensing steam from the dilution water heater in a closed-loop system provided by the ORC unit;
- Addition of an Atmospheric Flash Tank venting system that will only operate an estimated 50 hours per year when the ORC system is not operating;
- Increase the voltage of the electrical transmission lines from 161 kV to 230 kV with no changes to the number, height, or placements of the poles;
- Elimination of one of the two primary and secondary clarifier trains;
- Elimination of one of the two vacuum belt filters;
- Increased cooling tower footprint size and recirculation rate from 260,000 gallons/minute (gpm) to 323,635 gpm in order to support the additional heat rejection needs resulting from the increased plant capacity and ORC unit;
- Utilization of a counter flow cooling tower design as opposed to the cross flow design originally proposed;
- Revision in the distribution of the non-condensable gases and condensate makeup water introduction to more evenly distribute H₂S emissions in the cooling tower, which is being done to enhance cooling tower operation;
- Move the eastern 10-cell cooling tower 60 meters to the west;
- Addition of a 40 foot vent stack to each of the four atmospheric flash tanks for emergency relief only;
- Replacement of the biological H₂S abatement (oxidizer box) with a 91% efficient chemical abatement system, that will control the H₂S in the high pressure steam condensate stream, by using two aeration basins (each 80 feet by 50 feet by 10 feet

above grade) near the cooling towers to treat the hotwell condensate with hydrogen peroxide and Tower Brom 991 (or equivalent) prior to delivery to the cooling tower; and

- Extension of the project site's southern boundary by 328 feet (100 meters), increasing the project site by 19.4 acres (2,571 feet by 328 feet) to a total of approximately 100 acres.

Not all of the project design changes affect the air quality analysis for the SSU6 Project. However, several of the design changes would alter the construction and/or operations of the plant thereby changing the air quality emissions.

ANALYSIS

The analysis has been divided into two specific topics:

- 1) Design Changes and Related Impacts
- 2) Other Requested Revisions to the COCs

DESIGN CHANGES AND RELATED IMPACT ANALYSIS

Construction

Construction Emissions

For construction, the following modifications would affect air quality impacts:

- Increased emissions associated with the drilling of two additional wells, including trucking and worker travel;
- Addition of emissions from pile driving equipment;
- Decreased PM10 emissions from construction equipment due to the application of Tier 1 Diesel Engine Emissions Standards; and
- Increased fugitive dust emissions due to the expansion of the southern boundary of the plant site.

Tables 2 through 4 show the revised levels of criteria pollutants generated from construction activities as a result of the proposed design changes. The values from the Final Staff Assessment (FSA) are shown in parentheses for those quantities that have changed as a result of this amendment.

The hourly, daily, and annual construction equipment tailpipe PM10 emissions have been reduced through the use of revised emission factor assumptions that conform to the level of mitigation required in COC **AQ-C3**. The daily and annual fugitive dust PM10 emissions have been increased due to the larger project site area. Additionally, the annual construction emission estimate has been increased to account for a combination of increased construction equipment needs (i.e. pile driving equipment), increased well drilling, and increased well flow testing. However, the worst-case hourly and daily construction scenario and equipment use assumptions have not changed, so the worst-case hourly and daily equipment NO_x, CO, SO₂ and VOC emission estimates have not been revised.

Table 2
SSU6 Project Estimated Maximum Hourly Construction Emissions
For the Power Plant, Pipelines, and Transmission Lines, lb/hr

Source	NO _x	CO	VOC	SO _x	PM10	NH ₃	H ₂ S
Construction Equipment ^a	26.42	19.78	3.82	0.48	1.14 (1.49)	---	---
Delivery Trucks ^a	10.69	3.16	0.83	0.10	0.35	---	---
Worker Travel ^a	7.62	89.31	9.72	0.06	0.20	---	---
Fugitive Dust ^b	---	---	---	---	11.6 (11.7)	---	---
Sub-Total ^c	41.0	108.3	13.4	0.60	13.2 (13.4)	---	---
Well Drilling	25.97	3.17	0.36	0.73	1.07	---	---
Well Flow Testing	---	---	0.46 ^d	---	64.8	47.2	11.8
Total	67	111	14.2	1.3	79.1 (79.3)	47.2	11.8

Source: (CEC 2003a - FSA Part 1, Air Quality Table 10). CEOE 2004, Table 10R. Detailed calculations located in Appendix 2, Tables G-1R through G-1.6R (fugitive dust), G-2R (well drilling), G-3R to G-3.11R (construction equipment, worker travel, and delivery trucks), and G-4R (well flow testing).

Note(s):

- a. Maximum emissions calculated assuming 8 hours/day and 20 days/month.
- b. Fugitive Dust emissions include: erosion, delivery trucks, worker travel, and construction equipment. Erosion emissions are assumed to occur 24 hours/day, 30 days/month. All others are assumed to occur 8 hours/day, 20 days/month.
- c. Maximum emissions do not occur in the same month. The sub-total presented is the highest hourly emissions occurring during any one month.
- d. VOC emissions were originally based on benzene, toluene, and xylenes (BTX). Based on the project owner's revised VOC data the BTX totals were multiplied by 2.07 to include all VOC constituents.

Table 3
SSU6 Project Estimated Maximum Daily Construction Emissions
For the Power Plant, Pipelines, and Transmission Lines, lb/day

Source	NO _x	CO	VOC	SO _x	PM10	NH ₃	H ₂ S
Construction Equipment ^a	211.4	158	30.6	3.9	9.08 (11.9)	---	---
Delivery Trucks ^a	85.51	25.27	6.61	0.78	2.82	---	---
Worker Travel ^a	60.94	714.48	77.75	0.46	1.62	---	---
Fugitive Dust ^b	---	---	---	---	116.9 (114.0)	---	---
Sub-Total ^c	327.8	866.2	107.1	4.8	130.4 (128.9)	---	---
Well Drilling	623.3	76.08	8.64	17.52	25.68	---	---
Well Flow Testing	---	---	11.1 ^f	---	1,555	1,133	283.2
Total ^c	951	942	127	22.3	1,711 (1,710)	1,133	283.2

Source: (CEC 2003a - FSA Part 1, Air Quality Table 11). CEOE 2004, Table 11R. Detailed calculations located in Appendix 2, Tables G-1R through G-1.6R (fugitive dust), G-2R (well drilling), G-3R to G-3.11R (construction equipment, worker travel, and delivery trucks), and G-4R (well flow testing).

Note(s):

- a. Maximum emissions calculated assuming 8 hours/day and 20 days/month.
- b. Fugitive Dust emissions include: erosion, delivery trucks, worker travel, and construction equipment. Erosion emissions are assumed to occur 24 hours/day, 30 days/month. All others are assumed to occur 8 hours/day, 20 days/month.
- c. Maximum emissions do not occur in the same month. The sub-total presented is the highest hourly emissions occurring during any one month.
- d. Well Drilling maximum daily emissions are based on peak hourly emissions provided in Table 2, assuming 24 hours.
- e. Well Flow Testing maximum daily emissions are based on hourly emissions provided in Table G-4R, assuming 24 hours. Maximum hourly emissions are for a single production well.
- f. VOC emissions were originally based on benzene, toluene, and xylenes (BTX). Based on the project owner's revised VOC data the BTX totals were multiplied by 2.07 to include all VOC constituents.

Table 4
SSU6 Project Estimated Maximum Annual Construction Emissions
For the Power Plant, Pipelines, and Transmission Lines, tons/year

Source	NO _x	CO	VOC	SO _x	PM10	NH ₃	H ₂ S
Construction Equipment	23.3 (20.0)	17.0 (15.5)	3.3 (2.9)	0.4	0.98 (1.1)	---	---
Delivery Trucks	7.13	2.107	0.551	0.07	0.23	---	---
Worker Travel	6.32 (6.29)	74.1 (73.72)	8.06 (8.02)	0.05	0.17	---	---
Fugitive Dust	---	---	---	---	13.75 (13.13)	---	---
Sub-Total	36.75 (33.42)	93.21 (91.33)	11.9 (11.47)	0.54 (0.52)	15.13 (14.63)	---	---
Well Drilling ^a	139 (124.25)	17.0 (15.18)	1.91 (1.71)	3.90 (3.49)	5.73 (5.12)	---	---
Well Flow Testing ^b	---	---	0.25 (0.22) ^c	---	32.3 (29.8)	26.1 (22.9)	5.37 (5.00)
Total	175.75 (158)	110.2 (107)	14.0 (13.4)	4.4 (4.0)	53.2 (49.6)	26.1 (22.9)	5.37 (5.00)

Source: (CEC 2003a - FSA Part 1, Air Quality Table 12). CEOE 2004, Table 12R. Detailed calculations located in Appendix 2, Tables G-1R through G-1.6R (fugitive dust), G-2R (well drilling), G-3R to G-3.11R (construction equipment, worker travel, and delivery trucks), and G-4R (well flow testing).

Note(s):

- a. Well Drilling annual emissions are based upon 1006 days of drilling (increased from 900 days) and average fuel use (100% load equals 2284.8 gal/day – actual highest of three wells is 1012 gal/day or 44.3%).
- b. Well flow testing based on only one well being flow tested at a time. Annual emissions from production wells are based on 816 hours for 11 wells (increased from 768 hours for 10 wells). Annual emissions from injection wells are based upon 288 hours for 6 wells, as two wells will not be tested (increased from 240 hours for 5 wells). Four production wells - 96 hours per well. Four production wells - 72 hours per well. Rest of wells - 48 hours per well.
- c. VOC emissions were originally based on benzene, toluene, and xylenes (BTX). Based on the project owner's revised VOC data the BTX totals were multiplied by 2.07 to include all VOC constituents.

Construction Impacts

As discussed above, modifications with the potential to affect the ambient air quality during construction include the addition of two wells (one production, one injection), pile driving equipment emissions, and the increase in project site area (80-acres to 100-acres).

Table 5 shows the updated project owner air dispersion modeling results. The values from the FSA Addendum are shown in parentheses that have changed as a result of this amendment. It also should be pointed out that in this table and all subsequent air impact tables shown in this analysis, that the values shown in bold are for total impacts (project and background) that are above the applicable ambient air quality standards.

Table 5
Project Owner Construction Modeling Results

Pollutant	Averaging Period	Project Impact ($\mu\text{g}/\text{m}^3$)	Background Concentration ($\mu\text{g}/\text{m}^3$) ^a	Total Impact ($\mu\text{g}/\text{m}^3$) ^c	Limiting Standard ($\mu\text{g}/\text{m}^3$)	Type of Standard	Percent of Standard (%)
NO ₂ ^b	1-Hour	268	180	448	470	CAAQS	95
	Annual	5.8 (5.2)	25	30.8 (30.2)	100	NAAQS	31 (30)
PM ₁₀	24-Hour	39 ^c	129	168	50	CAAQS	336
	Annual Arith. Mean	5.0 ^c	48.6	53.6	20	CAAQS	268
CO	1-Hour	193	18,560	18,753	23,000	CAAQS	82
	8-Hour	111	8,262	8,373	10,000	CAAQS	84
SO ₂	1-Hour	19	73	92	655	CAAQS	14
	3-Hour	12	63	75	1,300	NAAQS	6
	24-Hour	5.5	5	10.5	105	CAAQS	10
	Annual	0.22 (0.2)	3	3.2	80	NAAQS	4
H ₂ S	1-Hour	16.2	24.6	40.8	42	CAAQS	97

Source: (FSA Addendum, Air Quality Table 22). CEOE 2004, Table 22R.

Note(s):

- a. Background concentration values for this table and all other modeling result tables have been adjusted to the staff recommended values shown in **AIR QUALITY Table 9 of FSA Part 1** (CEC 2003a) and as noted earlier in this assessment.
- b. The ozone limiting method (ISC3OLM) was used for 1-hour NO₂ concentrations. The ambient ratio method (factor 0.75) for rural areas was used for annual NO₂ concentrations.
- c. These are based on the CEC Modeling results from Air Quality Table 23 of FSA Part 2 (CEC 2003b) rather than the project owner's modeling results. Additionally, the CEC annual arithmetic mean modeling result of 4.7 $\mu\text{g}/\text{m}^3$ has been increased by the project owner's emission ratio of 53.2/49.6.
- d. All total impact results reflects changes in assumed background concentration, so the former modeling result values provided in parenthesis will not always match the values presented in the FSA.
- e. Results above AAQS are shown in bold.

Construction Mitigation and Conclusions

The construction impacts to existing receptors, as shown on Table 5, are very similar to those previously evaluated. It should be noted that the impacts shown are maximum fence-line impacts, and the impacts at the maximum exposed residential receptor will be much lower than the maximums shown in Table 5. Staff believes that the existing COCs that mitigate construction impacts (**AQ-C1** through **AQ-C4**, and **AQ-C10**) remain adequate to mitigate the construction air quality impacts to less than significant for the requested revised project.

Normal Operations

Operating Project Emission Calculation Revisions

The following proposed changes in operations and emissions controls, as well as modifications and revisions to the emission estimate methods, would affect air quality impacts:

- Increase in emissions (H_2S , PM10, ammonia) directly and/or indirectly as a result of increasing the brine flow to a maximum of 15.4 million pph (previously 12.8 million pph);
- Revision of the H_2S NCG/condensate partition from 80/20 to 60/40 based on source testing of CalEnergy's facilities in 2003 (CEOC, 2005, DR#14), which means that 60 percent of the H_2S contained in the steam separates into the non-condensable gas (NCG) stream while the remaining 40 percent condenses and stays with the condensate stream;
- Replacement of the biological H_2S abatement (oxidizer box) with a chemical abatement system for the high pressure condensate;
- Increase in PM10 emissions as a result of increasing the circulation rate of the cooling tower water (drift control efficiency remains at 0.0005 percent);
- Change in the offgassing of emissions from NCG and condensate to take place only at the first cooling tower cell;
- Elimination of the dilution water heater (DWH) emissions with the implementation of a Organic Rankine Cycle (ORC) unit; and
- Increase in VOC emissions due to the addition of an ORC unit.
- A new cooling tower H_2S partitioning factor that assumes that 43.5% is available to be emitted from the cooling tower in the form of dissolved H_2S while the remaining 56.5% is present in HS^- ion form which will not be emitted.

Equipment Operation

The fence line has been moved approximately 328 feet (100 meters) to the south, thereby increasing the approximate area for the power plant from 80 acres to 100 acres (Plant Site) of a 160-acre parcel within the unincorporated area of Imperial County, California. The added area is required to provide additional buffer to reduce the operational ambient air quality impacts and ensure compliance with the California Ambient Air Quality Standards (CAAQS) for H_2S (CEOE 2005, DR#13). An ancillary benefit of increasing the plant site is that this additional area will allow for storage of equipment and materials used for maintenance activities. Additionally, the increase in geothermal brine flow will require the installation of one additional production well and one additional injection well. Two injection wells and two production wells will be located on the plant site, and the remaining nine production wells (four well pads) and eight injection wells (three well pads) will be located offsite.

The project will be nominally rated at 200 MW (gross) and will generate up to approximately 215 MW (net summertime) of on-line power.

Emission Controls and Emission Assumptions

The new ORC unit condenses the steam release from the atmospheric flash tank (AFT). The ORC unit utilizes lower temperature, unused steam from the steam turbine and a secondary (i.e., binary) working fluid that passes through vaporizers, condensing in the condenser. Energy from the unused steam causes the secondary fluid, an organic compound, to flash to a vapor. This vapor drives two turbines. The ORC unit produces a small amount of NCG, which is periodically vented to a vapor recovery unit with an efficiency of 95 percent. This vapor recovery unit removes the volatile organic compounds (VOC) from the non-condensable vent gases. The NCG is extracted

periodically during normal operation from the ORC unit condenser. The cooling media for the ORC unit is cooling water that will be supplied from the cooling tower and will be provided to the greatest extent possible from geothermal condensate. The condensate used in the ORC unit is either 1) returned to the process for dilution water or 2) injected in the appropriate plant wells (shallow reinjection wells located on the plant site), depending on process need. The ORC unit VOC emission limit was originally requested to be 23 lbs/day (CEOE 2004); however, through local experience with similar isopentane ORC systems, the District is recommending a VOC emission limit of 65 lbs/day. The project owner, after a review of the DOC, agrees with the District and now requests that the VOC emission limit be increased to 65 lbs/day (CEOE 2005a). Staff believes that final confirmation of the 65 lbs/day needs to be determined after final design of the ORC unit, and has recommended COC **AQ-C16** to request that the project owner provide data to confirm the final ORC design VOC emission estimate.

The addition of the ORC will eliminate the need for the DWH exhaust stacks. Removing the DWH stacks will result in the conservation of water that was previously emitted as steam plumes, will reduce a source of visual impacts, and will increase electrical production without additional energy/resource consumption. However, the elimination of the DWH stacks requires the incorporation of a steam vent exhaust stack on each the Atmospheric Flash Tanks (AFTs) in the event of a situation requiring the release of steam at the SSU6 plant. Therefore, emergency vent stacks have been incorporated into the AFTs to accommodate this need. The AFT emergency vent stacks would only be expected to be used during emergency shutdowns to vent the steam generated by the process. The AFT emergency vent stacks, constructed on top of the 40 foot tall AFTs, would have a final stack height of 66 feet above grade and a stack diameter of 10 feet.

The oxidizer box H₂S emission reduction system (biofilter oxidizer cell) will be replaced with a chemical abatement system that will result in greater overall efficiency and operational reliability. The chemical abatement units consist of two aeration basins measuring 50 feet by 80 feet each covered with fiberglass reinforced plastic (FRP) made flat roofs to contain air discharged from the diffusers. Each basin will have a separate FRP vent pipe which will be connected to the cooling tower cell for air discharge (CEOE 2005, DR#11). The chemical abatement system will enable hotwell condensate from the turbines to oxidize H₂S into sulfates by the addition of air, hydrogen peroxide, and Tower Brom 991 (or an equivalent halide stabilizer chemical). The Tower Brom will be stored in a hopper with a storage capacity of approximately 3,000 pounds of dry material, located above a 2,000 gallon mixing tank. The water used for mixing will be condensate and not fresh water. The Tower Brom (in tablet form) will be mixed with water for addition to the chemical abatement system. The hydrogen peroxide will be stored in a 5,000-gallon fiberglass storage tank. These chemicals will be added to the cooling tower aeration basins to facilitate the oxidization of the H₂S and reduce emissions from the basin vents.

Two high pressure air blowers will introduce air into the chemical abatement system to provide a source of oxygen and to provide adequate mixing through approximately 2,350 fine bubble diffusers per basin, with each fine bubble diffuser capable of delivering 15 cubic feet per minute at 5 pounds per square inch. The system will oxidize H₂S into a sulfate form, which will be suspended in the condensate, and will be directed

to the cooling tower basins. The system is expected to have an overall H₂S control efficiency of 94 percent based on preliminary information from similar oxidization processes at industrial and municipal water treatment plants in the United States.

The two cooling towers approved in the original certification were a cross flow design with a recirculation rate of 260,000 gpm. The proposed cooling towers are a counter flow design with a total recirculation rate of 323,635 gpm, and each has a slightly larger footprint at 60 feet wide, 540 feet long, and 58 feet tall (to the top of the fan shrouds), but each tower is designed with the same number of cells (ten) and has a shorter main structure height and smaller overall internal volume.

During the original licensing review, it was assumed that the H₂S would partition 80 percent into the non-condensable gases (NCG) and 20 percent into the steam condensate (the vast majority into the high pressure steam condensate), which is used as makeup water in the cooling tower. Additional testing at other facilities has indicated that a better and more conservative estimate for the split would be 60 percent of the H₂S to the NCG and 40 percent of the H₂S to the steam condensate. The validity of this assumption was verified by ICAPCD (CEOE 2005) and this assumption will result in higher emissions and higher H₂S offset requirements as the chemical oxidation condensate H₂S control is not as efficient as the NCG LOCAT H₂S control.

The cooling tower H₂S emission estimating procedure has been revised with the incorporation of a H₂S chemical partitioning factor of 43.5 percent. Data from two literature sources suggest that between approximately 20 percent and 40 percent of the H₂S will remain free H₂S that can be released and the rest will be in an HS⁻ ion form. Staff is not challenging the validity of the references provided by the project owner for this new partitioning factor, or the relatively conservative 43.5 percent factor they are using based on this literature; however, staff is unsure if this factor may vary under different cycles of concentration or other specific cooling tower design and operating features that may be different than those encountered in the cited literature. Therefore, staff believes that this chemical partitioning factor needs to be verified through the required source testing and has added that requirement in the verification of condition **AQ-23**.

Operating Emissions

Tables 6 through 8 show the revised levels of criteria pollutants generated from operational activities as a result of the proposed design changes. The values from the FSA (CEC 2003b) are shown in parentheses for those quantities that have changed as a result of this amendment.

Table 6
SSU6 Project Maximum Hourly Emissions, lb/hr

Operational Source	NO_x	CO	VOC	SO_x	PM10	NH₃	H₂S
Cooling Tower – NCG ^a	---	---	0.47 (0.375)	---	---	0.14 (0.12)	0.673 (0.766)
Cooling Tower – Offgassing ^b	---	---	---	---	---	856 (712)	4.559 (3.374)
Cooling Tower – Drift	---	---	---	---	3.62 (2.91)	0.0008	---
Dilution Water Heater	---	---	---	---	---	---	---
					(0.14)	(16.54)	(0.678)
ORC Binary System	---	---	2.71 (---)	---	---	---	---
Filter Cake Silica	---	---	---	---	0.0077 (0.0064)	---	---
Filter Cake Sulfur	---	---	---	---	5.3E-5 (4.4E-5)	---	---
EG-480 Engine ^c	---	---	---	---	---	---	---
EG-4160 Engine ^c	34.24	2.19	0.82	1.15	0.65	---	---
Fire Pump Engine ^c	---	---	---	---	---	---	---
Operation & Maintenance (O&M) Equipment	5.49	29.55	1.70	0.27	0.063 (0.06)	---	---
O&M Fugitive Dust	---	---	---	---	0.077 (0.074)	---	---
Total Maximum Hourly Emissions (lb/hr)	39.73	31.74	5.70 (2.52)	1.42	4.42 (3.84)	856 (728.7)	5.23 (4.82)

Sources: (CEC 2003a - FSA Part 1, Air Quality Table 13). CEOE 2004, Table 13R. Detailed calculations located in Appendix 2, Tables G-6R through G-13R. CEOE 2005, Table 13R (O&M Fugitive Dust updated). CEOE 2005a.

Note(s):

- a. Non-condensable gases
- b. Offgassing includes H₂S emissions from the two covered aeration basins of the chemical abatement system, which will vent through separate vent pipes which will be connected to the cooling tower.
- c. The engines will not be tested at the same time, or on the same day.

Table 7
SSU6 Project Estimated Maximum Daily Emissions, lb/day

Operational Source	NO_x	CO	VOC	SO₂	PM10	NH₃	H₂S
Cooling Tower – NCG	---	---	11.3 (9.01)	---	---	3.36 (2.88)	16.15 (18.38)
Cooling Tower – Offgassing	---	---	---	---	---	20,544 (17,088)	109.42 (80.98)
Cooling Tower – Drift	---	---	---	---	86.9 (69.8)	---	---
Dilution Water Heater	---	---	---	---	---	---	---
					(3.26)	(396.96)	(16.27)
ORC Binary System	---	---	65 (---)	---	---	---	---
Filter Cake Silica	---	---	---	---	0.0616 (0.0512)	---	---
Filter Cake Sulfur	---	---	---	---	0.00128 (0.00107)	---	---
EG-480 Engine	---	---	---	---	---	---	---
EG-4160 Engine ^a	34.24	2.19	0.82	1.15	0.65	---	---
Fire Pump Engine	---	---	---	---	---	---	---
Operation & Maintenance (O&M) Equipment	43.90	236.41	13.58	2.18	0.5024	---	---
O&M Fugitive Dust	---	---	---	---	1.84 (1.78)	---	---
Total Maximum Daily Emissions	78.14 (79.14 – in FSA was typo)	238.60	90.7 (23.41)	3.33	89.92 (76.04)	20,547 (17,488)	125.57 (115.63)

Sources: (CEC 2003a - FSA Part 1, Air Quality Table 14). CEOE 2004, Table 14R. Detailed calculations located in Appendix 2, Tables G-6R through G-13R. CEOE 2005, Table 14R (O&M Fugitive Dust updated). CEOE 2005a.

Note(s):

a. Only one engine is tested for a maximum of 1 hour per day.

Table 8
SSU6 Project Estimated Maximum Annual Average Emissions, tons/year

Operational Source	NO _x	CO	VOC	SO ₂	PM10	NH ₃	H ₂ S
Cooling Tower – NCG	---	---	2.07 (1.64)	---	---	0.622 (0.526)	2.95 (3.36)
Cooling Tower – Offgassing ^a	---	---	---	---	---	3,225 (2,681)	24.8 (14.78)
Cooling Tower – Drift	---	---	---	---	15.85 (12.74)	0.0035	---
Dilution Water Heater	---	---	---	---	---	---	---
					(0.59)	(72.45)	(2.97)
ORC Binary System	---	---	11.86 (---)	---	---	---	---
Filter Cake Silica ^b	---	---	---	---	0.0017 (0.0014)	---	---
Filter Cake Sulfur ^b	---	---	---	---	3.51E-05 (2.92E-05)	---	---
EG-480 Engine ^c	0.24 (0.2)	0.01	0.002	0.01	0.0015 (0.001)	---	---
EG-4160 Engine ^c	1.71 (1.7)	0.11	0.04	0.06	0.03	---	---
Fire Pump Engine ^c	0.18 (0.2)	0.01	0.003	0.01	0.002	---	---
Operation & Maintenance (O&M) Equipment	1.72 (1.6)	11.28 (10.13)	0.61 (0.55)	0.35	0.0235 (0.0232)	---	---
O&M Fugitive Dust	---	---	---	---	0.331 (0.321)	---	---
Total Average Annual Emissions (tpy)	3.82 (3.7)	11.43 (10.24)	14.59 (2.24)	0.43	16.3 (13.71)	3,226 (2,754)	27.7 (21.11)

Sources: (CEC 2003a - FSA Part 1, Air Quality Table 15). CEOE 2004, Table 15R. Detailed calculations located in Appendix 2, Tables G-6R through G-13R. CEOE 2005, Table 15R (O&M Equipment and Fugitive Dust updated). CEOE 2005a.

Note(s):

a. Cooling tower offgassing gas annual ammonia emissions are based upon an annual average of 736 lbs/hr.

b. Annual average emissions for filter cake silica and sulfur are based on 0.009235 lbs/day and 0.00019 lbs/day, respectively.

c. Engine annual emissions based on 100 hours of operation.

Normal Operations Modeling Impact Analysis

Table 9 provides the revised emissions levels for on-site operations. The values from the FSA Addendum are shown in parentheses for those quantities that have changed as a result of this amendment.

Table 9
Project Owner Operation ISC Modeling Results

Pollutant	Averaging Period	Project Impact ($\mu\text{g}/\text{m}^3$)	Background Concentration ($\mu\text{g}/\text{m}^3$) ^a	Total Impact ($\mu\text{g}/\text{m}^3$) ^d	Limiting Standard ($\mu\text{g}/\text{m}^3$)	Type of Standard	Percent of Standard (%)
NO ₂ ^b	1-Hour	209	180	389	470	CAAQS	83
	Annual	0.53 (0.5)	25	25.5 (25.5)	100	NAAQS	26 (26)
PM10	24-Hour	3.1 (2.3)	129	132.1 (131.3)	50	CAAQS	264 (263)
	Annual Arith. Mean	0.32 (0.3)	48.6	48.9 (48.9)	20	CAAQS	245 (245)
CO	1-Hour	1,121	18,560	19,681	23,000	CAAQS	86
	8-Hour	458	8,262	8,720	10,000	CAAQS	87
SO ₂	1-Hour	22	73	95	655	CAAQS	15
	3-Hour	16	63	79	1,300	NAAQS	6
	24-Hour	7.0	5	12	105	CAAQS	11
	Annual	0.08	3	3.1	80	NAAQS	4
H ₂ S	1-Hour	17.1 ^c (12.0)	24.6	41.7 (36.6)	42	CAAQS	99 (87)

Source: (FSA Addendum and Data Response, Air Quality Table 24 and 24R, and Addendum Table 10). CEOE 2004, CEOE, 2005. Detailed calculations located in Appendix 2, G-23R and G-27R. CEOE 2005, Table 24R (PM10 24-hour and annual updated).

Note(s):

- Background concentration values for this table and all other modeling result tables have been adjusted to the staff recommended values shown in **AIR QUALITY Table 9 in FSA Part 1** (CEC 2003a) and as noted earlier in this assessment.
- The project owner lists only one diesel engine in the 1-hour modeling runs because the other two will not be tested while the original one is tested. A screening analysis indicated that the fire pump engine generated the highest NO₂ concentrations. The ambient ratio method (factor 0.75) for rural areas was used for annual NO₂ concentrations.
- The H₂S modeling result is based on 86% chemical oxidation efficiency, but emission limit will be based on 91% efficiency. Therefore, this result overstates the potential impact.
- All total impact results reflects changes in assumed background concentration, so the former modeling result values provided in parenthesis will not always match the values presented in the FSA.
- Results above AAQS are shown in bold.

The annual NO₂, 24-hour and annual PM10, and 1-hour H₂S impacts were found to be somewhat higher than estimated in the FSA. However, the NO₂ and H₂S impacts are below their respective AAQS and the increase in the PM10 impacts is minor. Additionally, the project's operating H₂S and PM10 emissions will be fully offset, and the project owner has increased the fence line buffer area to maintain the H₂S operating impacts below the AAQS. Therefore, staff has determined that the mitigated air quality impacts from the revised project operations remain less than significant.

Temporary Operating Emissions

Well Rework/New Well Drilling

Drilling emissions are expected to increase as a result of the addition of one production well and one injection well. The total number of wells will be twenty-one, consisting of eleven production and ten injection wells. The short-term emissions associated with reworking and/or drilling new wells are not expected to change because only one drilling rig would be present at a time; however, annual emissions would increase by approximately ten percent. Therefore, annual emissions are based on 55 days of drilling

each year versus the original 50 days in order to account of the increase in number of wells. Table 10 summarizes the revised well drilling emissions. The values from the FSA are shown in parentheses for those quantities that have changed as a result of this amendment.

Table 10
SSU6 Project Estimated Well Rework/New Well Drilling Emissions

	NO_x	CO	VOC	SO_x	PM10
Pounds Per Hour Per Well	25.97	3.17	0.36	0.73	1.07
Annual Emissions (tpy)	7.59 (6.90)	0.93 (0.84)	0.10 (0.09)	0.21 (0.19)	0.313 (0.285)

Source: (CEC 2003a - FSA Part 1, Air Quality Table 16). CEOE 2004, Table 16R. Detailed calculations located in Appendix 2, Table G-2R.

Note(s):

- a. NO₂, CO, VOC and PM10 emission factors based on Caterpillar documented emission data for 3412DITTA Engines, SO₂ based on 0.05% Sulfur fuel. Engine Hp based upon typical drill rig used in the Salton Sea area.
- b. Long term emissions are based upon 55 days per year of well rework drilling (vs. 1006 days for well field drilling) and average fuel use.

Well Flow Activities

It was previously estimated that 232 hours of production well flow testing was necessary. This estimate was based on three coil cleanings (144 hours); two warm-ups per ten wells (40 hours) and one redrill (48 hours). With the proposed changes, the total hours of well flow activities would be 284 based on three coil cleanings (144 hours), two warm-ups per eleven wells (44 hours), one re-drill (48 hours), and one re-drill or coil cleaning (48 hours).

Fifty-four hours were estimated for injection well flow operation (3 wells × 18 hours/well). With these changes, the hours would now total 72 (4 wells × 18 hours/well). Note that while there are ten injection wells, only four wells a year would need to be flowed back during maintenance operations.

Table 11 summarizes the revised emissions resulting from well flow activities. The values from the FSA are shown in parentheses for those quantities that have changed as a result of this amendment.

Table 11
SSU6 Project Estimated Well Flow Run Emissions ^a

	VOC ^d	PM10	NH ₃	H ₂ S
Production Well (lb/hr)	0.46 (0.47)	64.8	47.2	11.8
Injection Well (lb/hr)	0.46 (0.39)	41.0	47.2 (39.3)	3.9
Annual Emissions (tpy) ^{b,c}	0.07 (0.06)	10.7 (8.6)	8.4 (6.5)	1.8 (1.5)

Source: (CEC 2003a - FSA Part 1, Air Quality Table 17). CEOE 2004, Table 17R. Detailed calculations located in Appendix 2, Table G-14R.

Note(s):

- A well could be venting for a total of 48 hours. Only one well will be flow tested at a time.
- Annual emissions from production wells are based on 284 hours [44 hours for warm ups (2 warm-ups per 11 wells), 144 hours for three coil tubing clean-outs (48 hr/each), 48 hours for one re-drill, and 48 hours for one re-drill or coil cleaning].
- Annual emissions from injection wells are based on 72 hours for re-drilling four injection wells (18 hr/each).
- VOC emissions were originally based on benzene, ethylbenzene, toluene, and xylenes (BTX). Based on the project owner's revised VOC data the BTX totals were multiplied by 2.07 to include all VOC constituents. At a brine flow rate of 0.8 mlbs/hr this would amount to 0.46 lb/hr VOC (CEOE 2005, DR#18).

Steam Vent Tanks

Emissions from steam venting will increase as a result of changes in the cooling tower design, which are offset by the deletion of the dilution water heater vent stacks. Table 12 summarizes the revised emissions resulting from vent relief. The values from the FSA are shown in parentheses for those quantities that have changed as a result of this amendment.

Table 12
SSU6 Project Estimated Vent Relief Tank Emissions During Venting

	VOC ^b	PM10	NH ₃	H ₂ S
Vent Relief Tanks (total lbs/hr)	4.28 (0.50)	2.87	86.0	17.7
Cooling Tower (lbs/hr)	0.39 (0.25)	3.62 (2.92)	626 (546)	2.29 (3.75)
Dilution Water Heater (lbs/hr)	--- (0)	--- (0.136)	--- (16.5)	--- (0.678)
Annual Emissions (tpy) ^a	0.117 (0.019)	0.162 (0.148)	17.8 (16.2)	0.500 (0.553)

Source: (CEC 2003a - FSA Part 1, Air Quality Table 18). CEOE 2004, Table 18R. Detailed calculations located in Appendix 2, Table G-15R

Note(s):

- Annual emissions assume 50 hours at 100 percent load. Brine flow rate will average 12.8 million pph or less during venting.
- VOC emissions were originally based on benzene, ethylbenzene, toluene, and xylenes (BTX). Based on the project owner's revised VOC data the BTX totals were multiplied by 2.07 to include all VOC constituents. At a brine flow rate of 12.8 mlbs/hr this would amount to 0.74 lb/hr VOC. The value shown assumes all the potential VOC in the brine would be vented leading to an overestimation of the emissions (CEOE 2005, DR#19).

Plant Startup

With the addition of one production well, plant startup annual emissions would increase. Table 13 summarizes the revised emissions resulting from plant startup. The values from the FSA are shown in parentheses for those quantities that have changed as a result of this amendment.

Table 13
SSU6 Project Estimated Startup Emissions

	VOC ^e	PM10	NH ₃	H ₂ S
Production Test Unit (lbs/hr) ^a	0.46 (0.47)	64.8	47.2	11.8
100% Vent Relief Tanks (total lbs/hr) ^b	5.15 (0.50)	3.45 (2.87)	103.5 (86.0)	21.3 (17.7)
100% Cooling Tower (lbs/hr) ^c	0.47 (0.25)	3.62 (2.92)	857 (546)	5.20 (4.14)
100% Dilution Water Heaters (lbs/hr) ^c	--- (0)	--- (0.136)	--- (16.54)	--- (0.678)
Annual Emissions (tpy) ^d	0.02 (0.0088)	1.65 (1.48)	7.92 (5.14)	0.34 (0.305)

Source: (CEC 2003a - FSA Part 1, Air Quality Table 19). CEOE 2004, Table 19R. Detailed calculations located in Appendix 2, Table G-16R.

Note(s):

- A total of 50 hours will be venting at PTU emissions rates (0.8 million lbs/hr steam).
- A total of 5 hours at 5.82% of full flow will be venting at the vent relief tanks (VRTs), where 100% of flow based on 15.4 million pph brine flow rate.
- A total of 45 hours will be venting at Cooling Towers (emissions range from 5.82% to 58.2% of full flow).
- A period is one startup per year.
- VOC emissions were originally based on benzene, ethylbenzene, toluene, and xylenes (BTX). Based on the project owner's revised VOC data the BTX totals were multiplied by 2.07 to include all VOC constituents. At a brine flow rate of 0.8 mlbs/hr this would amount to 0.46 lb/hr VOC (CEOE 2005, DR#18).

Atmospheric Flash Tank

The ORC unit condenses the steam released from the atmospheric flash tank (AFT). The ORC system is capable of condensing the steam stream from the AFT even during certain conditions when one or both of the ORC unit turbines are off line. This means that the system is designed to bypass the ORC unit turbine generator and operate as a heat exchanger between the steam flow and the cooling tower flow. However, if one of the four ORC unit vaporizers must be placed out of service, a steam release would occur at the AFT system. Maintenance of the ORC unit will be scheduled during regular steam turbine generator overhauls to minimize emergency shutdowns. Table 14 summarizes the temporary emissions from the AFT.

Table 14
SSU6 Project Estimated Atmospheric Flash Tank Emissions

	PM10	NH ₃	H ₂ S
AFT (lb/hr)	13.6	39.80	0.816
Annual Emissions (tpy) ^a	0.34	0.99	0.02

Source: CEOE 2004, Table 19A. Detailed calculations located in Appendix 2, Table G-9R.

Note(s):

- A total of 50 hours per year estimated for annual emissions, which is the upper limit of potential emergency relief during any given year (CEOE 2005, DR #16).

Initial Commissioning

Commissioning would include an additional production well, which would also cause a slight increase in commissioning emissions. Table 15 shows the revised commissioning schedule, and Table 16 shows the revised commissioning emissions. The values from the FSA are shown in parentheses for those quantities that have changed as a result of this amendment.

Table 15
Estimated Power Plant Commissioning Schedule *

Commissioning Activities Task	Event Duration	Emission Location	Equivalent Emission Rates	
			VRT A/ VRT B Rate	VRT C/VRT D Rate
No. 1 Well Warm-up	18 hours	Production Test Unit	PTU (Well Startup)	PTU (Well Startup)
No. 1 Production Line Warm-up	6 hours	VRTs	2.6% (3.5%) of VRTs (total)	0
Preheat RPF Vessels	12 hours	VRTs	2.6% (3.5%) of VRTs (total)	0
No. 2 Well Warm-up	18 hours	Production Test Unit	PTU (Well Startup)	PTU (Well Startup)
No. 2 Production Line Warm-up	18 hours	VRTs	5.2% (7.0%) of VRTs (total)	0
No. 3 Well Warm-up	18 hours	Production Test Unit	PTU (Well Startup)	PTU (Well Startup)
No. 3 Production Line Warm-up	18 hours	VRTs	7.8% (10.5%) of VRTs (total)	0
No. 4 Well Warm-up	18 hours	Production Test Unit	PTU (Well Startup)	PTU (Well Startup)
No. 4 Production Line Warm-up	18 hours	VRTs	10.4% (14%) of VRTs (total)	0
No. 5 Well Warm-up	18 hours	Production Test Unit	PTU (Well Startup)	PTU (Well Startup)
No. 5 Production Line Warm-up	18 hours	VRTs	13% (17.5%) of VRTs (total)	0
No. 6 Well Warm-up	18 hours	Production Test Unit	PTU (Well Startup)	PTU (Well Startup)
No. 6 Production Line Warm-up	18 hours	VRTs	13% (17.5%) of VRTs (total)	3.15% (3.5%) VRTs (total)
No. 7 Well Warm-up	18 hours	Production Test Unit	PTU (Well Startup)	PTU (Well Startup)
No. 7 Production Line Warm-up	18 hours	VRTs	13% (17.5%) of VRTs (total)	5.2% (7%) VRTs (total)
No. 8 Well Warm-up	18 hours	Production Test Unit	PTU (Well Startup)	PTU (Well Startup)
No. 8 Production Line Warm-up	18 hours	VRTs	13% (17.5%) of VRTs (total)	7.8% (10.5%) VRTs (total)
No. 9 Well Warm-up	18 hours	Production Test Unit	PTU (Well Startup)	PTU (Well Startup)
No. 9 Production Line Warm-up	6 hours	VRTs	13% (17.5%) of VRTs (total)	10.4% (15.75%) of VRTs (total)
No. 10 Well Warm-up (NEW)	18 hours	Production Test Unit	PTU (Well Startup)	PTU (Well Startup)
No. 10 Production Line Warm-up (NEW)	18 hours	VRTs	13% of VRTs (total)	13% of VRTs (total)
HP Steam Blow (First Line – Train 1)	12 hours	HP Steam Blow Stack, VRTs	Steam Blow Stack 13% (15.75%) of Vent Tanks (SP, LP)	Steam Blow Stack 13% (15.75%) of Vent Tanks (HP, SP, LP)
HP Steam Blow (Second Line – Train 2)	12 hours	HP Steam Blow Stack, VRTs	Steam Blow Stack 13% (15.75%) of Vent Tanks (HP, SP, LP)	Steam Blow Stack 13% (15.75%) of Vent Tanks (SP, LP)
SP Steam Blow (First Line – Train 1)	12 hours	SP Steam Blow Stack, VRTs	Steam Blow Stack 13% (15.75%) of Vent Tanks (HP, LP)	Steam Blow Stack 13% (15.75%) of Vent Tanks (HP, SP, LP)
SP Steam Blow (Second Line – Train 2)	12 hours	SP Steam Blow Stack, VRTs	Steam Blow Stack 13% (15.75%) of Vent Tanks (HP, SP, LP)	Steam Blow Stack 13% (15.75%) of Vent Tanks (HP, LP)
LP Steam Blow (First Line – Train 1)	12 hours	LP Steam Blow Stack, VRTs	Steam Blow Stack 15.75% of Vent Tanks (HP, SP)	Steam Blow Stack 15.75% of Vent Tanks (HP, SP, LP)
LP Steam Blow (Second Line – Train 2)	12 hours	LP Steam Blow Stack, VRTs	Steam Blow Stack 15.75% of Vent Tanks (HP, SP, LP)	Steam Blow Stack 15.75% of Vent Tanks (HP, SP)
Turbine Preheat, Vacuum Test, and Other Tests	96 hours	Cooling Towers	Steam Blow Stack 13% (15.75%) of Vent Tanks (HP, SP, LP)	Steam Blow Stack 13% (15.75%) of Vent Tanks (HP, SP, LP)
Turbine Load Test, Etc.	18 hours	Cooling Towers	Steam Blow Stack 13% (15.75%) of Vent Tanks (HP, SP, LP)	Steam Blow Stack 13% (15.75%) of Vent Tanks (HP, SP, LP)
Turbine Performance Test	72 hours	Normal Operating Condition Emissions		

Source: (CEC 2003a - FSA Part 1, Air Quality Table 20). CEOE 2004, Appendix 2, Table G-5.1R.

- Times are approximate and subject to change when a more definitive startup program is developed. Some activities are scheduled to occur simultaneously, specifically the production line warm-up for a brine well (emissions through the VRT exhausts) normally occurs simultaneously with the well warm-up (emissions through the PTU unit exhaust) for the next brine well that is being brought online.

Table 16
Estimated Power Plant Commissioning Emissions

Source	Emissions Rate	Hours per Period	VOC ^a (lb/hr)	PM10 (lb/hr)	H ₂ S (lb/hr)	NH ₃ (lb/hr)
PTU	100%	180 (162)	0.46	64.8	11.8	47.2
Vent Relief Tanks (total)	100%	77.49 (71.82)	3.72 (7.40)	6.83	190	712.3 (786)
Dilution Water Heaters	100%	--- (143.6)	--- (0)	--- (0.136)	--- (0.68)	--- (16.5)
Cooling Tower	100%	71.82	0.39 (0.38)	3.62 (2.92)	4.32 (4.14)	712
Steamblow ^b	31.5% of full VRT rates	72	2.35 (0.78)	0.717	19.99	82.53
Total (tons/period)	---	---	0.3 (0.34)	6.25 (5.63)	9.3 (8.7)	58.4 (61.8)

Sources: (CEC 2003a - FSA Part 1, Air Quality Table 21). CEOE 2004, Table 21R. Detailed calculations located in Appendix 2, G-5R through G-5.6R.

Note(s):

a. VOC emissions were originally based on benzene, toluene, and xylenes (BTX). Based on the project owner's revised VOC data the BTX totals were multiplied by 2.07 to include all VOC constituents.

b. Steamblow emissions (lb/hr) are estimated based on the lbs/period divided 72 hours.

The total VRT and PTU flows do not change, so the worst case commissioning impacts, which are based on the emissions from those units, will not be increased by this amendment. Therefore, the impact assessment and conclusion regarding the short-term impacts do not change. However, the first year PM10 and H₂S offset requirements are adjusted to account for the small increase in total commissioning emissions that result from the slightly increased commissioning period due to the additional production well. Therefore, the long-term impacts will be mitigated and the overall finding of insignificant impacts does not change.

Potential Temporary Activities Impacts

The project owner also revised the emissions estimates for temporary activities such as well rework/new well drilling, well flow activities, steam vent tanks, and plant startup as a result of project design changes. The revised estimate is provided in Table 17. The values from the FSA are shown in parentheses for those quantities that have changed as a result of this amendment.

Table 17
Project Owner Temporary Activities ISC Modeling Results

Pollutant	Source	Averaging Period	Project Impact ($\mu\text{g}/\text{m}^3$)	Background Concentration ($\mu\text{g}/\text{m}^3$) ^a	Total Impact ($\mu\text{g}/\text{m}^3$) ^c	Limiting Standard ($\mu\text{g}/\text{m}^3$)	Type of Standard	Percent of Standard (%)
NO ₂	Well Rework	1-Hour	236	180	416	89	CAAQS	83
PM ₁₀	Well Rework	24-Hour	3.5	129	132.5	50	CAAQS	265
	Well Flow	24-Hour	36	129	165	50	CAAQS	330
	Steam Vent Tanks	24-Hour	3.4 (1.8)	129	132.4 (130.8)	50	CAAQS	265 (262)
	Plant Startup	24-Hour	20.9 (20.7)	129	149.9 (149.7)	50	CAAQS	300 (299)
	AFT Release	24-Hour	10.9 (---)	129	139.9 (---)	50	CAAQS	278 (---)
CO	Well Rework	1-Hour	82	18,560	18,642	23,000	CAAQS	81
	Well Rework	8-Hour	31	8,262	8,293	10,000	CAAQS	83
SO ₂	Well Rework	1-Hour	18.9	73	91.9	655	CAAQS	14
	Well Rework	3-Hour	12	63	75	1,300	NAAQS	6
	Well Rework	24-Hour	2.4 ^b	5	7.4	105	CAAQS	7
H ₂ S	Well Flow	1-Hour	16.2	24.6	40.8	42	CAAQS	97
	Steam Vent Tanks	1-Hour	15.3 (16.8)	24.6	39.9 (41.4)	42	CAAQS	95 (99)
	Plant Startup	1-Hour	16.9 (17.0)	24.6	41.5 (41.6)	42	CAAQS	99 (99)
	AFT Release	1-Hour	0.65 (---)	24.6	25.3 (---)	42	CAAQS	60 (---)

Source: (CEC 2003a - FSA Part 1 and Data Response, Air Quality Table 25 and Table 25R, and Addendum Table 11). CEOE 2004, CEOE 2005. Detailed calculations located in Appendix 2, G-24R and G-28R.

Note(s):

- a. Background concentration values for this table and all other modeling result tables have been adjusted to the staff recommended values shown in **AIR QUALITY Table 9 in FSA Part 1** (CEC 2003a) and as noted earlier in this assessment.
- b. This value was determined through a review of the modeling output files provided by the project owner, which conflicts with the value presented in AFC Table 5.1-81 (2.8 $\mu\text{g}/\text{m}^3$).
- c. All total impact results reflects changes in assumed background concentration, so the former modeling result values provided in parenthesis will not always match the values presented in the FSA.
- e. Results above AAQS are shown in bold.

The impacts from the revised temporary operating activities are similar in quantity to those evaluated in the FSA. The short-term NO₂, CO and SO₂ impacts remain below their respective AAQS. Additionally, the temporary PM₁₀ and H₂S emissions from all on-site temporary activities will remain fully offset. Therefore, staff has determined that

the mitigated air quality impacts from the revised project temporary activities remain less than significant.

Mitigation and Emission Offsets

Based on the project design changes, the total normal operating emissions for the project would also change. Table 18 provides a summary of the revised operational emissions. The values from the FSA are shown in parentheses for those quantities that have changed as a result of this amendment.

Table 18
Total Normal Operating Emissions

Pollutant	Tons/Year	Lbs/Day ^a (annual average)
NO _x	3.82 (3.7)	20.9 (20.3)
CO	11.43 (10.24)	62.6 (56.1)
VOC	14.59 (2.24)	38.0 (12.3)
SO ₂	0.4	2.4
PM10	16.3 (13.71)	89.3 (75.1)

Source: (CEC 2003b - FSA Part 2, Table 28). CEOE 2004, Appendix 2, Table G-13R. CEOE 2005, Table 15R (O&M Equipment and Fugitive Dust updated).

Note(s):

a. Assume 365 days/year

Due to the overall increase in emissions from the SSU6 Project, additional offsets will be necessary. Table 19 summarizes the revised offsets for the project. For operations, the H₂S offset amount increased from 27.69 to 35.94 tons. For well testing, the H₂S offset amount increased from 5.00 to 5.4 tons (see Table 4). For commissioning, the H₂S offset amount has increased from 8.7 to 9.3 tons; while for PM10 the offset amount has increased from 5.63 to 6.25 tons (see Table 14).

Table 19
Mitigation Measures

Source(s)	Offset Amount	Offset Source
SSU6 (27.7 tpy) x 1.2 + temporary emissions (2.7 tpy) x 1 = 35.94	35.94 tons H ₂ S	Leathers LP 38 MWe Geothermal Power Plant
Well Flow Testing (temporary)	5.4 tons H ₂ S 32.3 tons PM10	H ₂ S from Leathers LP emission control. PM10 from ERC Stationary or Ag Bank.
SSU6 PM10 (permanent) (Mitigation Agreement July 24, 2003)	19.6 tons PM10 7.8 tons NO _x ¹ 14.59 tons VOC ¹	ERC Stationary or Ag Bank.
Commissioning (temporary)	9.3 tons H ₂ S 6.25 tons PM10	H ₂ S from Leathers LP emission control. PM10 from ERC Stationary or Ag Bank.

¹ These offsets would occur through the agricultural burning cessation along with the PM10 offsets that are banked. It is recommended that the amount of VOC offsets be demonstrated to meet this level annually (COC **AQ-C17**).

This table shows that the direct PM10 and H₂S emissions will be fully offset. Additionally, the NO_x and VOC emissions will be offset by the use of the Agricultural Bank PM10 emission reduction credits. The District does not currently include the

banking of the NO_x and VOC emission reductions from burning cessation; therefore, staff considers these indirect emission reductions to be accountable to the project owner for CEQA mitigation purposes. The District's 2004 Agricultural ERC bank is dominated by two crops (Bermuda grass and wheat) that account for approximately 90 percent of the total burn cessation acres. Using available emission factors (USEPA 1992 and proprietary reference) this indicates that the corresponding NO_x emission reduction from agricultural burning cessation would be on the order of at least 40 percent of the PM₁₀ emission reduction and the corresponding VOC emission reduction would be at least 60 percent of the PM₁₀ emission reduction (using wheat as the lowest VOC emission factor ratio crop). Since the annual NO_x and VOC emissions are only approximately 20 percent and 35 percent of the PM₁₀ emission offset requirement, using agricultural burning emission reduction credits to offset the PM₁₀ emissions will more than offset the project's NO_x and VOC emissions. The annual VOC emissions are approximately 75 percent of the annual PM₁₀ emission offset requirement, which is greater than the worst-case VOC/PM₁₀ percentage ratio that would result if only wheat burn cessation credits are used. However, the project owner will likely have to obtain additional PM₁₀ emission offsets for annual well testing maintenance operations (approximately 10 tons per year of PM₁₀ offsets) and the crop average VOC reduction for 2004 was well over 75%. Therefore, staff has determined that the project owner will be able to offset the VOC emissions using the agricultural burning cessation ERCs necessary to offset the PM₁₀ emissions; however, in order to provide annual confirmation, staff is recommending COC **AQ-C17**, which will require the project owner to annually demonstrate that the VOC emissions are fully offset by the burn cessation credits that are used each year.

Staff considers the small amount of project SO₂ emissions, which are a concern as a PM₁₀ precursor in an ammonia rich environment, to be offset through the required excess in PM₁₀ offsets. The combination of normal operating SO₂ and PM₁₀ emissions (0.4 and 16.3 tons/year) are less than the normal operating PM₁₀ offset requirement of 19.6 tons/year.

CONDITIONS OF CERTIFICATION

Staff recommends that the revisions to the COCs that deal strictly with the revisions to the project design that have been proposed by the project owner or modified by the ICAPCD should be approved. Specifically, this addresses the revised staff conditions **AQ-C11**, **AQ-C14**, and new recommended staff condition **AQ-C16**; and the new, revised or deleted District conditions **AQ-4** to **AQ-9**, **AQ-16**, **AQ-17**, **AQ-21** to **AQ-23**, **AQ-26** to **AQ-28**, and **AQ-39** to **AQ-45** provided in this assessment.

OTHER REQUESTED REVISIONS TO CONDITIONS OF CERTIFICATION

Description of Request

The project owner has requested several other changes to both staff and District COCs that are not directly related to the changes in project design. These include:

- Deletion of Staff Condition **AQ-C12**;

- Replacement of term “independent” with term “certified” in **AQ-C15** to describe the laboratory requirements for the completion of the water sample analysis used to show emission rate compliance;
- Delete “CARB” and “EPA” from the list of inspecting agencies in various condition verifications;
- Revise the well drilling recordkeeping requirements of **AQ-15**;
- Revise the wording to clarify **AQ-19**;
- Specify “LOCAT” and the H2S control system in question for **AQ-20**;
- Revise the source testing requirements in **AQ-23** to delete the ammonia testing requirement and lower the frequency from annual testing to testing every four years for the other specified pollutants.
- Revise condition **AQ-28** to include the revised cooling tower condensate H2S control technology and eliminate cooling tower shroud source testing requirements in favor of water based mass balance emission testing.
- Delete condition **AQ-31** that requires plant startup notification.
- Delete the requirement in **AQ-32** that all official source tests be witnessed by APCD staff.
- Revise the source test report due date in condition **AQ-33** from 30 to 60 days after the performance of the test.
- Make a minor continuity correction to condition **AQ-34** deleting the term “mole” and adding “ppmv”.
- Make a minor typographical correction to COC **AQ-37** to include the word “order”.

CONCLUSIONS

Staff has made the following conclusions, in consultation with the ICAPCD, for each of these COC revision requests:

Staff Conditions

Staff condition **AQ-C12** requires that the project owner provide quarterly emission estimates of ammonia emissions through chemical testing and mass balance or other CEC approved means. Staff does not believe that the project owner has provided a compelling reason to delete CEC staff condition **AQ-C12**. In fact, since ICAPCD has deleted all ammonia testing requirements as requested by the project owner, staff believes this condition to be vital. This project may result in the emissions of more than 3,000 tons of ammonia. Ammonia is a pollutant of concern and information regarding major emission sources of ammonia is valuable. Staff does not believe that the requirement of simple and inexpensive inlet/outlet cooling tower water tests to determine actual ammonia emissions from the cooling tower to be overly burdensome. Staff would also like to point out that ammonia emission estimates from gas turbine project SCR units are always required, and that those emissions are over an order of magnitude lower than the forecast ammonia emissions from this project. Therefore, staff recommends that this condition be retained.

Staff does not believe that the deletion of the requirement of the use of an independent laboratory as noted in COC **AQ-C15** is prudent. The specific testing requirements of **AQ-C15** are not otherwise required by District conditions or other third party source

testing requirements. Therefore, third party confirmation of the test results is necessary for these tests. However, staff does agree that the term “certified” is a reasonable addition to this condition and does recommend its inclusion.

Staff does not believe that deleting “CARB” and “EPA” from this staff standard condition verification is prudent or necessary. Staff believes that both CARB and EPA would have inspection rights at the SSU6 facility. For example CARB may wish to inspect the ambient monitoring station as part of making it a certified station, or CARB or EPA may want to inspect engines that would be regulated under their diesel engine emission specification regulations. Additionally, each agency may have inspection rights under other programs such as the AB2588 Air Toxics Inventory program (CARB) or Risk Management Plan program (EPA).

District Conditions

Staff recommends the revisions as recommended in the District DOC. The District has revised or deleted many conditions, most in agreement with the project owner’s requests. However, some of the conditions have been deleted or changed in a manner completely different from the project owner’s original request. Staff revised the verifications for Conditions **AQ-15** and **AQ-31** with the intent of meeting the project owner’s requests for those conditions. The only specific request not addressed by the District was Condition **AQ-32** requiring that all official source tests be witnessed by APCD staff. The District did not agree with the requested revision.

CONCLUSIONS AND RECOMMENDATIONS

Staff finds that the requested project design changes and associated requested changes to the conditions of certification, with the exceptions noted elsewhere in this assessment, are reasonable and will not cause significant air quality impacts. Therefore, staff recommends that the COCs be revised as recommended below.

The following list of conditions are those that are proposed for revision. Any conditions from the Commission Decision not shown here are not proposed for revision. Recommended additions are shown in **bold**, double underlined text, whereas recommended deletions are shown in strikethrough text.

STAFF CONDITIONS OF CERTIFICATION

AQ-C11 The project owner shall provide through chemical monitoring and mass balance, or other means approved by the CPM, quarterly PM10 emission estimates for the SSU6 plant to demonstrate that the annual operational emissions are no more than ~~13.74~~ **16.3** tons/year on a rolling 12-month basis.

Verification: The project owner/operator shall provide the CPM with a proposed PM10 emission estimation methodology within 30 days of the start of commercial operations and shall provide the PM10 emissions estimates in the Quarterly Operations Report.

AQ-C14 The emissions of particulate matter less than 10 microns (PM10) from the Cooling Towers shall not exceed ~~2.94~~ **3.62** lbs/hr, and the drift eliminator shall be designed to limit drift to no more than 0.0005% of the circulating water flow.

Verification: The project owner shall provide copies of the cooling tower specifications and a vendor warranty of the drift efficiency to the CPM 60 days prior to cooling tower equipment delivery on-site.

AQ-C15 Compliance with the Cooling Towers PM10 emission limit shall be determined by circulating water sample analysis by independent **certified** laboratory within 60 days of commercial operation and quarterly thereafter.

Verification: The results and field data collected from cooling tower blowdown water samples analysis shall be submitted to the CPM as part of the Quarterly Operations Reports.

AQ-C16 The project owner shall confirm the ORC unit's isopentane average emissions estimate of 65 lbs/day based on actual final design specifications prior to installation of the ORC unit.

Verification: At least 60 days prior to installing the ORC unit, the project owner shall submit to the CPM vendor information regarding the specific system piping components (pumps, compressors, valves, flanges, etc.) and expected leak rates of each that confirms that an average leak rate of 65 lbs/day is attainable for the ORC unit.

AQ-C17 The project owner shall confirm on an annual basis that the Agricultural Burn Credit offsets obtained to meet the annual PM10 offset obligations would also provide VOC emission reductions that are equal to or greater than the annual estimated annual VOC emissions of 14.59 tons per year.

Verification: The project owner shall submit to the CPM, with the PM10 offset confirmation as required in Condition AQ-5, a calculation showing that the VOC emission reductions (as calculated using AP-42 Section 2.5) from the Agricultural Burn Cessation Credits used to offset the PM10 emissions would be sufficient to offset the project's annual VOC emissions.

DISTRICT CONDITIONS

The following list of conditions are those that are proposed for revision. Any conditions from the Commission Decision not shown here are not proposed for revision. Recommended additions are shown in **bold**, double underlined text, whereas recommended deletions are shown in ~~strikeout~~-text.

SS Unit 6 Operations Specification and Permit Limitations

Compliance

AQ-4 The facility shall be constructed to operate in **substantial** compliance with the project description, and operating parameters of the Application For Determination Of Compliance and AFC Application dated July 2002, **and the amended application dated January 13, 2005,** except as may be modified by more stringent requirements of law or these conditions. Non-compliance with any condition(s) or emission specification of this Permit shall be considered a violation and subject to fines and or imprisonment. This Permit does not authorize the emissions of air contaminants in excess of those allowed by USEPA (Title 40 of the Code of Federal Regulation), the State of California Division 26, Part 4, Chapter 3 of the Health and Safety Code, or the APCD (Rules and Regulations). This permit cannot be considered permission to violate applicable existing laws, regulations, rules or statutes of other governmental agencies.

Verification: The project owner shall demonstrate compliance status in the Quarterly Operations Reports. **Compliance with AQ-4 is demonstrated through complying with AQ-1 through AQ-45.**

Emission Offsets

AQ-5 The project owner shall provide, before the construction, placement or testing of any emission source(s), offsets in tons listed per source or sources listed below in TABLE A: Offsets may be in the form of ERCs (Emission Reduction Credits) owned by certified ERC holders registered with the Imperial County Air Pollution ERC Agricultural or Stationary Bank. ERCs must be transacted and validated through the APCD. ~~New well drilling will not coincide with any other stationary emissions source for the entire project that will trigger offsets for other pollutants (other than NO_x and PM₁₀) greater than 137 lbs/day threshold.~~ The actual calculated emissions per source has been multiplied by the ratio 1.2 to 1 to comply with offsetting ratio requirements of Rule 207 for permanent stationary sources and 1 to 1 for temporary sources.

Table A

SOURCE(S)	OFFSET AMOUNT	OFFSET SOURCE
SSU6 (27.7 24.1 tpy) x 1.2 + temporary emissions (2.7 0.9 tpy) x 1	35.94 26.64-tons H ₂ S	Leathers LP 38 MWe Geothermal Power Plant (70 tpy H ₂ S <u>currently permitted at 99.8 tpy</u> uncontrolled) control with Biofilters, sparging (<u>repermitted to 71.4 tpy for unit 6 offsets</u>) or APCD approved system.
Well Flow Testing (temporary)	5.4 5.00-tons H ₂ S 32.3 29.8-tons PM ₁₀	H ₂ S from Leathers LP emission control. PM ₁₀ from ERC Stationary or Ag Bank.
SSU6 PM ₁₀ (permanent) (Mitigation Agreement July 24, 2003)	19.6 tons PM ₁₀	<u>PM₁₀ from</u> ERC Stationary or Ag Bank.

Commissioning (temporary)	9.3 8.7 tons H ₂ S 6.25 5.63 tons PM10	H ₂ S from Leathers LP emission control. PM10 from ERC Stationary or Ag Bank.
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On or Before the Operation of any emission source(s) listed above, the Project Owner shall have provided to the APCD, ERC certificate(s):

- **equaling to or exceeding 35.9 tons of H₂S from the Leathers geothermal power plant;**
- **equaling to or exceeding 19.6 tons of PM10 (permanent) ERCs from the Stationary Source and/or AG Burning Emission Credit Bank;**
- **equaling to or exceeding 32.3 tons of PM10 (temporary) ERCs from the AG Burning Emission Credit Bank. The 32.3 tons of PM10 certificates may be provided and divided between each of the 17 wells before flow testing.**
- **equaling to or exceeding 6.25 tons of PM10 (temporary) ERCs from the AG Burning Emission Credit Bank before commissioning.**

Verification: The project owner/operator must submit all H₂S ERC documentation to the District and the CPM prior to the start of construction. At least 30 days prior to project commissioning, the project owner shall identify and surrender the permanent and commissioning operations PM10 ERCs to the District in the amount shown above and shall provide the CPM with documentation of the ERC surrender. Until such time as the project owner has committed traditional stationary source ERCs to cover the entire permanent offset burden, the project owner shall annually provide to the CPM and the District the agricultural burn secession ERCs being used to offset the project's PM10 emissions prior to each calendar or operational year, as required by the District. The project owner shall identify and surrender the well flow testing PM10 ERCs to the District as required in the District permit.

AQ-6 ~~**Deleted.** install and have in operation a biofilter system, sparging system, or other APCD approved system at the Leathers LLC power plant capable of reducing 25.3 tons/yr (5.77 lbs/hr) of H₂S at all times.~~

Verification: ~~_____ The project owner/operator shall make arrangements for periodic inspections of the Leathers LLC power plant by representatives of the District, CARB, USEPA and CEC.~~

AQ-7 ~~**Deleted.** The total emissions rate of Leathers LLC H₂S shall not exceed 17.03 lbs/hr after the installation of the bio-filtrations system.~~

Verification: ~~_____ The project owner/operator shall submit records of compliance as part of the Quarterly Operations Reports.~~

AQ-8 ~~**Deleted.** obtain PM₁₀ offsets in the total amount of 19.6 tons PM₁₀ per operating year. Offsets may be obtained through the APCD's Stationary Source and/or Agricultural Burning Emission Reduction Credits (ERCs) Bank list registered with the APCD. The Project owner shall have ERC Certificates in their possession totaling a minimum of 19.6 tons PM₁₀ at all times during the operation of SS Unit 6. The Project~~

owner shall surrender 19.6 tons PM_{4.0} ERC certificate(s) to the APCD prior to initial startup and annually thereafter.

Verification: At least 30 days prior to project commissioning, the project owner shall identify and surrender PM_{4.0} ERCs in the amount shown above. Until such time as the project owner has committed traditional stationary source ERCs to cover the entire offset burden, the project owner shall annually provide to the CPM and the District the agricultural burn cessation ERCs being used to offset the project's PM₁₀ emissions prior to each calendar or operational year, as required by the District.

AQ-9 ~~**Deleted.** The Leather's LLC Permit to Operate # 1927E H₂S emission rate shall be revised to reflect AQ-7 above.~~

Verification: The project owner/operator shall maintain the latest version of the Leathers' LLC Permit to Operate on site for the duration of the SS Unit 6 operating lifetime, or until H₂S offsets from a different source have been obtained, and shall be provided to District or CPM upon request.

Well Drilling

AQ-15 The project owner shall submit to the APCD **total** fuel usage and hours of **drilling** operation **no later than February 28th of each year for the preceding year.** records.

Verification: The project owner/operator shall submit fuel usage and hours of **drilling** operation to the District and CPM **no later than February 28th of each year for the preceding year.** 30 days after completion of well drilling.

Geothermal Power Plant Startups

AQ-16 Upon plant startups, the project owner shall

- Notify APCD of the time duration of the anticipated startup;
- **Vent high pressure steam to condenser at all times during startup.** Vent high pressure steam to condenser as soon as technically feasible during startup;
- Notify APCD upon completion of startup.

Verification: The project owner/operator shall notify the District and CPM seven (7) days prior to an anticipated startup, including both the estimated time and duration of the startup. The project owner/operator shall notify the District and CPM within three (3) days after completion of a startup. The project owner/operator shall make the site available for inspection by representatives of the District, CARB, USEPA and CEC.

Geothermal Power Plant Emissions Standards

AQ-17 Under normal operations, the project owner shall not exceed a plant wide total emission rate of the following:

Hydrogen Sulfide (NCG + CT Offgassing + <u>Basin Vent DWH</u>) <u>(0.67 lbs/hr + 5.6 lbs/hr +0.02 lbs/hr)</u>	6. 348 lbs/hr
Hydrogen Sulfide (NCG + CT Offgassing + DWH)	4.81 lbs/hr over a 24 hour average
Hazardous Organics <u>and Inorganics</u> (NCG + CT Offgassing + DWH)	<u>0.220</u> 0.180 lbs/hr over a 24 hour average
NCG = exhaust from H2S abatement system CT Offgassing = cooling tower offgassing <u>from condensate water makeup</u> DWH = Dilution Water Heater Stacks <u>Basin Vent = Vents from High Pressure Condensate Chemical Treatment Unit</u>	

Verification: The project owner/operator shall submit records of compliance as part of the Quarterly Operations Reports.

Geothermal Steam Venting Emissions Standards

AQ-19 Emissions of uncontrolled standard and low pressure noncondensable **gases** shall be calculated from most recent source tests.

Verification: The project owner/operator shall submit records of compliance as part of the Quarterly Operations Reports.

Monitoring

AQ-20 The project owner shall install and maintain in good working order an APCD approved continuous H2S in-stack monitor and flow gas meter at the H2S control system exhaust (**LOCAT**). The flow gas meter and in-stack monitor shall meet all specification, calibration, accuracy and quality assurance checks as set forth by the manufacturer. The monitor shall be equipped with a data logger capable of recording the continuous gas flow (SCFM) and H2S concentrations in PPBv/ PPMv and lbs/hr.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and CEC.

AQ-21 The project owner shall submit to the APCD an approved performance test protocol. Testing shall not be conducted without prior APCD approval. **no later than 30 days before the plant's commissioning an approved performance test protocol for Unit 6. The test protocol shall be capable of measuring Unit 6's total H2S and HAPs concentrations and emission rates. The plan shall include the measuring of total sulfides in the high pressure, standard and low pressure condensate and include a monthly sampling of benzene concentration from the carbon absorption unit and H2S concentration from the LOCAT polishing unit exhaust. The monitoring plan shall include a method to monitor and measure the condensate H2S abatement system. Monthly reporting of monitoring to the APCD shall commence 60 days after completion of the performance tests. Upon APCD**

approval, the sampling and measuring may be modified after an emissions baseline as been established for Unit 6.

Verification: Thirty (30) days prior to commissioning performance testing the owner/operator shall provide a written test and emissions calculation protocol for District and CPM review and approval. The approved protocol shall be in place when written notice for the initial performance tests is submitted. Written notice of the performance test shall be provided to the District ten (10) days prior to the tests so that an observer may be present. A written report with the results of such performance tests shall be submitted to the District and CPM within sixty (60) ~~forty-five (45)~~ days after testing. The performance source test shall verify the cooling tower H2S emission partitioning fraction of 0.435 used in the project amendment emissions calculations. The approved monitoring protocol shall be in place prior to the end of the initial commissioning period. The monitoring data required in this condition shall be submitted to the APCD monthly and shall be provided to the CPM in the Quarterly Operations Reports.

AQ-22 ~~**Deleted.** The project owner shall establish and submit an approved monitoring protocol and method(s) for monitoring and calculating cooling tower (offgassing) H₂S offgassing and benzene emissions from carbon absorption unit.~~

~~**Verification:** ——— Thirty (30) days prior to initial commissioning the project owner shall submit a monitoring protocol and method(s) for monitoring and calculating cooling tower H₂S offgassing and benzene emissions from carbon absorption unit for District and CPM review and approval. The approved monitoring protocol shall be in place prior to the end of the initial commissioning period.~~

AQ-23 Unless waived by the APCO, After the performance test, the project owner shall perform a complete annual-source testing every four years at (1) the LOCAT/Solid bed H₂S scavenger unit/Carbon adsorption exhaust for H₂S and HAPs organic and inorganic emissions Benzene emissions+ total speciated organic emissions+ total speciated metals; and (2) at the cooling tower cells exhaust for H₂S and ammonia, and cooling tower water for HAPs organic and inorganic emissions, benzene emissions+ total speciated organic emissions+ total speciated metals, and (3) the Dilution Water Heater (DWH) exhaust emissions for H₂S and benzene emissions+ total speciated organic emissions+ total speciated metals and total PM₁₀.

Verification: The required annual-source test report shall be submitted to the District and CPM as part of the Quarterly Operations Reports. Each annual subsequent source test report shall either include the results of the initial performance compliance test and supplemental source tests for the current period year or document the date and results of the last such tests. Each subsequent source test shall re-verify the cooling tower H2S emission partitioning fraction of 0.435 used in the project amendment emissions calculations.

AQ-26 ~~**Deleted.** In-stack monitoring equipment shall be available for inspection by the APCD at all times.~~

Verification: ~~_____ The project owner shall make the site available for inspection by representatives of the District, CARB, USEPA and CEC.~~

AQ-27 ~~**Deleted.** The project owner shall measure and submit to the APCD monthly, in an approved format, the H₂S concentration from the continuous H₂S monitor and benzene concentrations from the carbon absorption units(s).~~

Verification: ~~_____ The data required in this condition shall be submitted to the APCD monthly and shall be provided to the CPM in the Quarterly Operations Reports.~~

AQ-28 ~~**Deleted.** The project owner shall submit to the APCD the H₂S concentration (ppmv) and H₂S mass flow (lb/hr) measured at the non-condensable gas line before the abatement on a monthly basis. The project owner shall measure the efficiency of the cooling tower oxidizer boxes by measuring the flow rate and H₂S concentration of the condensate inlet and the H₂S outlet of the oxidizer boxes on a weekly basis and; the project owner shall measure the pH and temperature of the condensate at the inlet of the oxidizer boxes on a weekly basis. All sampling and analysis shall be performed on the same day. The project owner shall source test all cooling tower shrouds annually.~~

Verification: ~~_____ The data required in this condition shall be submitted to the APCD monthly and shall be provided to the CPM in the Quarterly Operations Reports.~~

Reporting Requirements

AQ-31 The project owner shall notify the APCD before plant startups.

Verification: The project owner/operator shall notify the District and the CPM at least seven (7) days prior to an anticipated startup, including both the estimated time and duration of the startup. **For unanticipated shutdown events the project owner shall notify the District and CPM, within 24 hours after the unanticipated shutdown, of the shutdown time and the actual or anticipated startup time.**

AQ-33 The project owner shall submit source test results to the APCD no later than ~~60~~**30** days after the initial performance test. All source tests after the performance test shall be submitted no later than February 28th of the subsequent year for the preceding year results.

Verification: Copies of the required source tests shall be submitted to the CPM and the District simultaneously by the schedule required in this condition.

AQ-34 The project owner shall submit to the APCD monthly, the benzene mole concentrations (**PPMv**), mass rate (lbs/hr) and total NCG gas flow rate (SCFM and lbs/hr) from the carbon absorption units no later than 15 days the subsequent month for the preceding month and; ~~the project owner shall submit to the APCD monthly, the continuous H₂S concentration (PPMv) and~~

Mass (lbs/hr) no later than 15 days the subsequent month for the preceding month.

Verification: The APCD required monthly concentration and flow data shall be provided to the CPM in the Quarterly Operations Reports.

AQ-35 The project owner shall submit annual fuel consumption and hours of operation of diesel standby equipment no later than February 28th of each year for the **preceding** subsequent year use.

Verification: The project owner/operator shall submit to the CPM the annual fuel consumption and hours of operation of diesel standby equipment in the Quarterly Operations Report for each fourth quarter.

Control and Monitoring Equipment Maintenance

AQ-37 The H₂S and carbon absorption control, and drift eliminators and or other future control devices and monitoring equipments shall be maintained in good working **order** and operating at its maximum control efficiency level specified in accordance to the operating instructions.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, USEPA and CEC.

ORC Unit Emission Standards

AQ-39 **The project owner shall not allow more than 65 lbs/day of isopentane fugitive and Integrated Vapor Recovery Unit (IVRU) losses averaged over a calendar quarter from the ORC unit(s) under normal operating conditions.**

Verification: **The project owner shall report in the Annual Compliance Report, the amount of isopentane purchased and estimate quarterly and quarterly average daily emissions based on mass balance calculations.**

AQ-40 **The ORC IVRU shall be in good working operating condition and operating without any leakages above normal specifications.**

Verification: **The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and CEC.**

AQ-41 **The project owner shall submit to the APCD and CEC an ORC inspection and maintenance plan; and shall include an isopentane monitoring leakages control program and leakage control plan. The plan shall include the manufacturer's ORC isopentane leakage specifications.**

Verification: The project owner shall submit the ORC inspection and maintenance plan to the CPM for approval at least 60 days prior to operation of the ORC unit.

ORC Unit Reporting Requirements

AQ-42 The project owner shall report to the APCD and CEC CPM all breakdowns of the ORC units within 24 hours. The report shall include the reason(s) for the breakdown, anticipated time until back online, and the amount of isopentane in pounds or gallons lost to atmosphere.

Verification: The project owner shall notify the APCD and the CEC CPM of an ORC breakdown within 24 hours of the ORC breakdown event. The project owner shall provide an estimate of the breakdown isopentane emissions within 7 days of the breakdown.

AQ-43 The project owner shall submit a report to the APCD and CEC CPM quarterly, that includes gallons of isopentane receivables for the quarter. The first reporting quarter shall have the set timing of the IVRU purging and number of purges that occurred for the quarter and the number of normal operating hours of the ORC and the number of hours not in operation. This report shall include the total amount of daily losses of isopentane under normal operation and the total number of losses in gallons due to breakdowns. The report shall be submitted to the APCD and CEC CPM no later than 30 days after the reporting quarter.

Verification: The APCD required quarterly isopentane receivables, emission data, and IVRU purge data shall be provided to the CEC CPM in the Quarterly Operations Reports.

Monitoring

AQ-44 The project owner shall measure and submit to the APCD quarterly, H2S brine concentrations prior to flash. The condition may be waived by the APCD after the first year of full operation.

Verification: The APCD required H2S brine concentrations data shall be provided to the CEC CPM in the Quarterly Operations Reports.

Organic Storage

AQ-45 The project owner shall comply with all vapor recovery and storage requirements of the District Rules.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and CEC.

REFERENCES

California Air Resources Board (CARB). 2002. California Ambient Air Quality Data 1980-2001 CD ROM. December 2002.

California Air Resources Board (CARB). 2005a. Area Designation Maps available on-line. Website: www.arb.ca.gov. Accessed January 13.

California Air Resources Board (CARB). 2005a. California Ambient Air Quality Data available on CARB Website. <http://www.arb.ca.gov/adam/>. Accessed March 2005.

California Energy Commission (CEC). 2003a. PART 1 - Final Staff Assessment on Salton Sea Unit #6 Project (Docket No. 02-AFC-2). August 5, 2003.

_____. 2003b. PART 2 - Final Staff Assessment on Salton Sea Unit #6 Project (Docket No. 02-AFC-2). September 29, 2003

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CalEnergy Obsidian Energy, LLC (CEOE). 2004. Final Salton Sea Unit 6 License, California Energy Commission, Amendment 1, December, 2004.

CalEnergy Obsidian Energy, LLC (CEOE). 2005. Response To: California Energy Commission Data Requests, Air Quality on Salton Sea Unit 6 License, California Energy Commission, Amendment 1, January 31, 2005, March 7, 2005, and March 15, 2005.

CalEnergy Obsidian Energy, LLC (CEOE). 2005a. Comments To: Air Pollution Control District (APCD) Determination of Compliance with Air Emissions Rules and Regulations. April 8, 2005.

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United States Environmental Protection Agency (USEPA). 1992. AP-42, Fifth Edition - Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Section 2.5 Open Burning. Available on-line at <http://www.epa.gov/ttn/chief/ap42/ch02/final/c02s05.pdf>. Accessed April 2005, published October 1992.

United States Environmental Protection Agency (USEPA). 2005. Green Book. Attainment designations available on-line. Website: www.epa.gov/air/oagps/greenbk/ accessed January 13.

**SALTON SEA GEOTHERMAL UNIT #6 (02-AFC-2C)
PETITION TO ADD A BINARY-CYCLE TURBINE AND INCREASE
GENERATION
BIOLOGICAL RESOURCES ANALYSIS
NATASHA NELSON
APRIL 2005**

SUMMARY OF CONCLUSIONS

CalEnergy Obsidian Energy LLC (project owner) filed an amendment in December 2004 which contained several design changes to the geothermal power plant that was approved by the Commission in December 2003. No construction has begun on the facility or its linear facilities; however, pre-construction surveys for burrowing owls and other sensitive species were completed in early 2004. The design changes proposed in the amendment were evaluated by staff and the project owner for the same suite of impacts that were identified during the siting case review:

1. Loss of burrowing owl habitat
2. Disturbance to sensitive populations from noise and human presence
3. Avian collisions with transmission lines
4. Wildlife collisions with construction vehicles
5. Brine spills and accidents (their size and frequency)
6. Placement of fill in a wetland feature (amounts and location)
7. Hydrogen sulfide, ammonia and sulfur dioxide impacts on neighboring lands
8. Loss of hunting-related parking and access
9. Loss of flat-tailed horned lizard habitat

The design changes proposed are fully mitigated with implementation of the existing conditions of certification, with the exception of burrowing owl habitat losses. Staff and the project owner have agreed to revise Condition of Certification BIO-25 to protect additional burrowing owl habitat and thus mitigate the project's larger footprint.

The design changes proposed in the Amendment have the potential to affect federally protected species and their habitat. However, in general the Amendment causes a minimal increase in impacts to biological resources, so the U.S. Army Corps of Engineers (USACE) determined that no changes to the existing Biological Opinion were warranted. The U.S. Fish and Wildlife Service (USFWS) concurred with their decision and no permit modifications are needed (Roberts 2005).

LAWS, ORDINANCES, REGULATION, AND STANDARDS

The LORS reference in the Final Staff Assessments (August 2003, October 2003) and the Commission Decision (December 2003) are applicable to this proposed amendment, and there are no additional LORS.

The project owner supplied the Amendment materials to the USACE in December 2004. The USACE is the federal lead for the project, and as such they applied to the USFWS for the incidental take (e.g, harass, harm, kill) of federally protected species that may result from the construction and operation of the power plant and its associated facilities. A Biological Opinion, granting incidental take of federally protected species, was issued to the USACE in November 2003. The USACE must determine relative to Section 7 of the Endangered Species Act if the project changes proposed in the Amendment are significant enough to warrant a modification to the Biological Opinion. (This type of permit modification is also known as a re-initiation of consultation.) The USACE determined the project would not have impacts that warranted a new Biological Opinion and the USFWS agreed (Roberts 2005). The current Biological Opinion and its Terms and Conditions are valid and therefore the project is in compliance with LORS.

SETTING

The proposed project site and linear facility routes would be located at the southern end of the Salton Sea in Imperial County. The Salton Sea provides feeding, resting, and nesting habitat for birds and supports a diversity of wildlife species throughout the year. The Sonny Bono Salton Sea Wildlife Refuge (Refuge) actively manages agricultural lands, wetlands, and upland habitat to supply foraging and nesting opportunities to the many birds that migrate to the Salton Sea. However, the majority of the land surface in the project area is subject to regular disturbance from agricultural activity. On the agricultural lands there is little or no cover or suitable nesting habitat above one foot from the surface; but there is foraging habitat for species that prey on small mammals and insects. There are currently several geothermal facilities in the region similar to this project.

In March 2004 the approved power plant site, laydown area, parking, well pads and associated linears, excluding the transmission linears were surveyed for burrowing owls (CE Obsidian Energy LLC 2004a). While many burrowing owls and potential burrows were located, no other sensitive species were identified. In April and May 2004, the wetlands on the south edge of the Salton Sea were surveyed for Yuma clapper rail and California black rail (CE Obsidian Energy LLC 2004b). During these surveys, Yuma clapper rails were detected at Rock Hill Marsh and Union Pond, but not detected in McKendry Marsh or the irrigation drainage areas. California black rails were not detected at any of the survey locations. These survey results are consistent with the Final Staff Assessment and Commission Decision. The sensitive species identified in the Final Staff Assessment (BIOLOGICAL RESOURCES Table 1) would still be expected to occur in the local area, however there are no additional species or locations to be evaluated under this amendment.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

The suite of potential impacts to biological resources from the construction and operation of the geothermal power plant are categorized as follows:

1. Loss of burrowing owl habitat
2. Disturbance to sensitive populations from noise and human presence
3. Avian collisions with transmission lines
4. Wildlife collisions with construction vehicles
5. Brine spills and accidents (their size and frequency)
6. Placement of fill in a wetland feature (amounts and location)
7. Hydrogen sulfide, ammonia and sulfur dioxide impacts on neighboring lands
8. Loss of hunting-related parking and access
9. Loss of flat-tailed horned lizard habitat

An assessment of these impacts and a discussion of mitigation is discussed below.

The potential for the permanent loss of burrowing owl habitat was identified at the power plant site, at the transmission line tower's locations and at the geothermal brine well pads. The design changes in the amendment include an increased voltage wires along the transmission line, expansion of the power plant site, but no changes to the size of the well pads. While there would be a change in the transmission line voltage, this does not result in more loss of habitat since the tower's pads would be the same size as initially analyzed and no new staging areas would be anticipated. Increasing the power plant site by 19.4 acres requires modification to Condition of Certification BIO-25. After implementation of the revised Condition of Certification, the impact to burrowing owl habitat would be less than significant.

Noise and vibration impacts were a concern during the original licensing of the power plant because the Refuge boundary is directly adjacent to two of the brine production well pads and is within 500 feet of the power plant facility. The design changes do not increase noise or vibration levels, but may require workers to be in the area for longer periods of time. Specifically, incorporating a new well on OB-2 well pad could extend drilling activities for one additional month and the additional pipeline could expand the construction time line by one week. So long as the project owner abides by the construction windows proposed in the Condition of Certification BIO-16, all impact to sensitive wildlife would be mitigated to less than significant levels. The project owner has requested a minor procedural change to Condition of Certification BIO-12 to accommodate the removal of protective heat pads from the brine pipelines during operational testing. Staff sees no biological resource consequences to the procedural change, and accepts the change as proposed.

The increased voltage will increase the conductor size used when stringing the line, but will not add additional lines, nor change the line's approved route. Such changes do not raise the collision risk to birds. So long as the project owner adheres to Condition of Certification BIO-17, no significant impacts are expected.

Traffic to and from the construction sites will cross lands used by sensitive wildlife and migratory birds. Collisions with construction vehicles was determined to be a potentially significant impact, and the project was required to have a worker education program (Condition of Certification BIO-4) and to manage the speed that construction related vehicles travel in highly sensitive habitat (Condition of Certification BIO-13). The design changes in the amendment will increase traffic levels overall, but implementation of these conditions will reduce the risk to sensitive wildlife and migratory birds to less than significant levels.

The potential for geothermal brine spills was considered a significant risk to biological resources. The brine pipeline are installed above ground and cross many streams, canals, and even wetlands. The project owner has designed the pipeline with the highest level of protection at all water crossings in order to prevent spills from getting into waterways. In addition, emergency spill management procedures will be developed by the project owner in consultation with the resource agencies (Condition of Certification BIO-20). The increase in geothermal brine volume and the addition of a brine pipeline can be managed under the existing Conditions of Certification, and no revisions are being proposed.

In order to connect the OB-3 well head to the power plant site, a road to its remote location must be widened. This results in the placement of fill within a wetland, which was permitted by the USACE. The additional brine pipeline proposed in the amendment does not cross wetlands and would not change the design for the OB-3 brine pipeline, so no additional wetland impacts are anticipated.

Normal power plant operations are likely to deposit pollutants and salts on the surrounding lands. The original level of pollutants was expected to cause only adverse, but not significant impacts. The design changes will increase the level of pollutants, but the levels are still anticipated be below the thresholds that are known to cause injury in sensitive plants.

The location of OB-1 and OB-2 wellheads is used by the Refuge for parking during the hunting season and also provides hunting opportunities for snow geese and widgeon. During and after construction, these opportunities will be reduced, and the project owner is required under Condition of Certification BIO-C9 to provide alternative lands. As a result of the design change, the project owner may spend a longer period of time in construction at the OB-2 well head, and may disturb slightly more land, however the implementation of Condition of Certification BIO-C9 is adequate to offset the loss.

Flat-tailed horned lizards may be present on the segment of transmission line between State Highway 86 and the connection to the L-line. The project owner is required to offset any habitat losses under Condition of Certification BIO-22. The increased voltage proposed in the amendment will not require changes to the number of towers or their location, so no additional habitat disturbance is expected, and no further mitigation is required.

CONCLUSIONS

The amendment materials provided by the project owner adequately covered the impacts, and the proposed changes to the Conditions of Certification are acceptable to staff. The project owner and staff have agreed to a procedural change in Condition of Certification BIO-12 and to an increased amount of mitigation land for burrowing owls under Condition of Certification BIO-25. All the necessary permits for the Amendment have been obtained by either the project owner or the federal lead, and the project is in compliance with LORS.

To ensure the Amendment does not result in significant impacts to biological resources and remains in compliance with all LORS, the following Conditions of Certification should be adopted.

REVISIONS TO EXISTING CONDITIONS AND PROPOSED CONDITIONS OF CERTIFICATION

Deleted text is shown in ~~strikethrough~~, added text bold and double **underlined**.

Preventative Design Mitigation Features

- BIO-12** The project owner shall modify the project design to incorporate all feasible measures that avoid or minimize impacts to the local biological resources such as the following.
1. Design, install, and maintain transmission line poles, access roads, pulling sites, and storage and parking areas to avoid identified sensitive resources and preferentially use previous pull sites or already disturbed locations;
 2. Avoid wetland loss to the extent possible when placing facility features;
 3. Design, install, and maintain facilities to prevent brine spills from endangering adjacent properties and waterways that contain sensitive habitat;
 4. Schedule disposal of brine within brine ponds as expeditiously as possible;
 5. Design, install, and maintain facility lighting to prevent side casting of light towards wildlife habitat;
 6. Insulate production and injection well pipelines and flanges, **except during maintenance, NDE testing and repair activities;**
 7. Prescribe a road sealant that is non-toxic to wildlife and plants and use only fresh water when adjacent to wetlands, rivers, or drainage canals;
 8. Equip steam blow piping with a temporary silencer that quiets the noise of steam blows to no greater than 74 dBA measured at a distance of 100 feet. Orient the silencer to maximize the noise reduction achieved in occupied Yuma clapper rail habitat to the north and northwest of the project site (i.e., Union Pond, McKendry Pond and Obisidean Butte).

9. Shield pile driving equipment to maximize noise reduction in the occupied Yuma clapper rail habitat to the north and northwest of the project site (i.e., Union Pond, McKendry Pond and Obsidian Butte).
10. Design, install, and maintain transmission lines and all electrical components to reduce the likelihood of electrocutions of large birds by following the Avian Power Line Interaction Committee (APLIC)'s *Suggested Practices for Raptor Protection on Power Lines: The State of the Art in 1996*;
11. Route the reject reverse osmosis water to the service water pond in lieu of the brine ponds, and
12. All mitigation measures and their implementation methods shall be included in the BRMIMP.

Verification: All mitigation measures and their implementation methods shall be included in the BRMIMP.

Provide Habitat Compensation for Permanent Disturbance to Burrowing Owl Habitat

BIO-25 Foraging habitat which is permanently destroyed shall be replaced at 0.5:1 (mitigation:impacts) and managed for the protection of burrowing owls. Based on these ratios, the project owner must protect and manage ~~42~~52.65 acres of land for burrowing owls (~~40~~50 acres for the power plant site and 2.65 acres for the transmission line pads). The mitigation amount can be reduced if mitigation land for the same burrowing owls is also being provided under Condition of Certification BIO-19.

Verification: At least 15 days prior to site mobilization, the project owner shall provide the CPM, USFWS, Refuge, and CDFG with the burrowing owl survey results. If burrowing owls are present where a permanent facility will be placed or within 300 feet of a permanent facility, the project owner shall identify the amount of land they intend to protect 15 days prior to construction. The project owner shall fund the acquisition and long-term management of the compensation lands in a form acceptable to the CEC and CDFG (e.g., provide a letter of credit or establish an escrow account) 15 days prior to construction. The land protection proposal and management fund(s) shall be approved by the CPM and reviewed by CDFG. The project owner shall propose land for purchase or protection with a description of habitat types and propose a management and monitoring plan at least 90 days prior to commercial operation.

The project owner shall rectify any underfunded amounts in the acquisition and long-term management account(s) at least 60 days prior to commercial operation. At least 30 days prior to commercial operation, the project owner shall submit to the CPM two copies of the relevant legal paperwork that protects lands in perpetuity (e.g., a conservation easement as filed with the Imperial County Recorder), a final management and monitoring plan, and documents which discuss the types of habitat protected on the parcel. If a private mitigation bank is used, the project owner shall provide a letter to the

CPM from the approved land management organization stating the amount of funds received, the amount of acres purchased and their location, and the amount of funds dedicated to long term monitoring or management 60 days prior to commercial operation. If funds remain after performance of all habitat compensation obligations, the monies in the letter of credit or escrow account will be returned to the project owner with written approval of the CPM.

All mitigation measures and their implementation methods shall be included in the BRMIMP.

REFERENCES

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**SALTON SEA GEOTHERMAL UNIT #6 (02-AFC-2C)
PETITION TO ADD A BINARY-CYCLE TURBINE AND INCREASE
GENERATION
DESIGN, RELIABILITY, EFFICIENCY AND NOISE ANALYSES
STEVE BAKER
JANUARY 2005**

REQUEST

CE Obsidian Energy, LLC (CEOE) requests to amend the Salton Sea Unit 6 project to:

- Add one geothermal production well and one brine reinjection well with associated piping;
- Increase geothermal brine flow approximately 18 percent to produce approximately an additional 15 MW of electrical power;
- Add an Organic Rankine Cycle (ORC) turbine generator to increase electrical power output approximately an additional 10 MW;
- Eliminate redundant clarifier trains and vacuum belt filters;
- Increase cooling tower size and change its configuration; and
- Add 40-foot emergency steam relief stacks to the atmospheric flash tanks.

BACKGROUND

The Salton Sea Unit 6 project was certified by the Energy Commission as a 185 MW geothermal power plant employing a triple flash, three-pressure steam turbine generator cycle. This technology represented the most efficient generating technology yet applied to this geothermal resource. When the project owner solicited bids from engineering/construction firms, the proposals received recommended certain improvements to the project that would increase generation efficiency and reduce per-kilowatt capital cost. Accordingly, CEOE seeks to amend the project certification to allow incorporation of these improvements.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

At the time of certification, LORS applicable to Noise and to Facility Design were identified in staff's Final Staff Assessment. These LORS will continue to apply to the amended project. No LORS apply to Efficiency or Reliability.

ANALYSIS

Prior development at the Salton Sea Known Geothermal Resource Area (KGRA) utilized single- or double-flash steam production technology and single-pressure steam turbine generators, chiefly because this inefficient technology was cheap to build. The Salton Sea Unit 6 project was the first one permitted in the Salton Sea KGRA to use the more efficient triple-flash technology with a three-pressure steam turbine generator, promising more efficient utilization of the geothermal resource.

Now, engineering companies bidding to design and construct the project have identified potential improvements that will increase power output (and thus, revenue) while better controlling construction and operating costs. The greatest contributors to an improved project are increasing the geothermal brine supply (through provision of an additional production well and its associated reinjection well), and installing a bottoming cycle consisting of an Ormat Organic Rankine Cycle turbine generator. The additional well will increase plant power output by approximately 15 MW, while the Ormat turbine will increase output by another 10 MW.

EFFICIENCY

Measures of fuel efficiency commonly applied to fossil fuel-burning power plants are not appropriate for a power plant utilizing a renewable (and, essentially, “free”) resource such as geothermal heat. Rather, the salient measure of efficiency is that of power output related to installed cost, or dollars per kilowatt. The proposed changes to the project will increase power output by approximately sixteen percent while increasing construction costs a lesser amount, resulting in a more cost-effective plant.

Adding an additional geothermal production well will allow the brine producing facilities to be utilized to greater capacity, resulting in greater power output from the triple-pressure steam turbine generator without a concomitant increase in steam production cost. Adding the Ormat bottoming cycle will allow the project to capture low-temperature heat in the atmospheric flash steam,¹ heat otherwise wasted to the atmosphere, and generate approximately an additional 10 MW. The only penalty is the capital cost of installing the additional equipment.

The efficiency of the modified project will be substantially greater than of the project as certified. There will therefore be no adverse impacts on project efficiency.

RELIABILITY

The added geothermal production well adds to reliability by providing a redundant supply of geothermal resource. The Ormat turbine, which has been available for many years for low-temperature power production in uses such as solar and geothermal power plants, has a proven track record of reliability. Deletion of redundant equipment such as brine clarifier trains will not impact project reliability, as this redundancy was the result of conservatism prompted by incomplete design studies.

The modified project will present no adverse effect on reliability.

FACILITY DESIGN

The project will be designed and constructed to comply with all applicable engineering codes and standards. The modified features described in the Petition for Amendment will present no unusual challenges; all the changes described will likely be designed and constructed in compliance with LORS.

¹ Formerly wasted steam at 228°F will be cooled to 135°F to power the ORC turbines (Petition for Amendment, Figure 2b).

NOISE AND VIBRATION

Noise and vibration impacts from the modified project could potentially be produced by both construction and operation of the modified facility.

The construction and operation of the modified portions of the project can be expected to produce noise and vibration impacts similar to those of the certified project; no new procedures or equipment are contemplated that would introduce significantly different impacts.² Any differences in noise or vibration impacts, then, would be produced if portions of the modified project were constructed and operated in locations nearer to sensitive noise and vibration receptors than the certified project.

Sensitive receptors of concern include humans (residents at the headquarters facility of the Sonny Bono Salton Sea Wildlife Refuge) and migratory birds. Any construction and equipment operation related to the modification will occur in the NW portion of the project site. The Refuge residence lies well to the NE of the project site; any noise or vibration related to the modification will travel a greater distance to this receptor than was previously analyzed in the original licensing proceeding. Therefore, any noise and vibration impacts on humans due to the modification should be less, and thus should not create any new impacts.

The migratory bird habitat of concern includes the Union Pond, approximately 400 feet N of wellpad OB1 (location of the new reinjection well), and a wetland at the intersection of McKendry and Severe Roads, approximately 600 feet W of wellpad OB2 (location of the new production well). The only meaningful difference in noise and vibration impacts due to the modification will be slightly increased periods of well drilling and pipeline installation.³ Since all drilling will be performed within the seasonal restrictions imposed on the originally certified project, no significant adverse impacts are expected.

In its Petition for Amendment, CEOE requests that Noise Condition of Certification **NOISE-6** be modified to reduce restrictions on project noise during plant startup, shutdown and upset, and whenever steam relief valves operate. Such easing of restrictions can be expected to increase noise impacts on sensitive receptors. Energy Commission staff does not agree with these requested changes to **NOISE-6**, and does not recommend they be incorporated in the amendment.

MITIGATION MEASURES AND CONDITIONS

The original project certification included twenty Facility Design Conditions of Certification and eight Noise and Vibration Conditions of Certification. These Conditions will provide adequate assurance that the modified project will comply with engineering

² The modified project may, in fact, produce less noise than the certified project. There will be three brine injection pumps instead of four, and six fewer primary and secondary clarifier system pumps. Pipeline noise will not increase noticeably due to increased flow, steam vent stacks will be adequately muffled, and the redesigned cooling tower will produce noise similar to the original design (Petition for Amendment, pp. 32-33).

³ Well drilling may be extended by one month at each location, and pipeline installation by one week (Petition for Amendment, p. 29, § 3.2.1).

codes and standards, and will present no adverse noise or vibration impacts beyond those found acceptable in the original proceeding.

In its Petition for Amendment, CEOE requests that Facility Design Condition of Certification **GEN-2, Table 1**, be modified to reflect the changes in equipment to be included in the modified project. Energy Commission staff agrees with these modifications to **Table 1**. These changes are shown below in bold and double underline/~~strikethrough~~:

GEN-2 Prior to submittal of the initial engineering designs for CBO review, the project owner shall furnish to the CPM and to the CBO a schedule of facility design submittals, a Master Drawing List and a Master Specifications List. The schedule shall contain a list of proposed submittal packages of designs, calculations and specifications for major structures and equipment. To facilitate audits by Energy Commission staff, the project owner shall provide specific packages to the CPM when requested.

Verification: At least 60 days (or project owner and CBO approved alternative timeframe) prior to the start of rough grading, the project owner shall submit to the CBO and to the CPM the schedule, the Master Drawing List and the Master Specifications List of documents to be submitted to the CBO for review and approval. These documents shall be the pertinent design documents for the major structures and equipment listed in **Facility Design Table 1** below. Major structures and equipment shall be added to or deleted from the table only with CPM approval. The project owner shall provide schedule updates in the Monthly Compliance Report.

Table 1: Major Structures and Equipment List

Equipment/System	Quantity (Plant)
Steam Turbine (ST) Foundation and Connections	1
Steam Turbine Generator Foundation and Connections	1
Steam Condenser and Auxiliaries Foundation and Connections	1
Condensate (HP) Hotwell Pumps Foundation and Connections	2
Condensate (SP/LP) Hotwell Pumps Foundation and Connections	2
Condensate Storage Tank Foundation and Connections	1
Filter Press System Structure, Foundation and Connections	1
Thickener Foundation and Connections	2
Brine Production Wellpads	5
Brine Injection Wellpads	3
Purge Water Pumps (HP/SP/LP) Foundation and Connections	6
Main Transformer Foundation and Connections	1
Counterflow Cooling Tower Foundation and Connections – 10 cells each	2
Vertical Circulating Water Pumps Foundation and Connections	6
Blowdown Pumps Foundation and Connections	2
Cooling Tower Wetdown Pumps Foundation and Connections	2

Equipment/System	Quantity (Plant)
Auxiliary Cooling Water Pumps Foundation and Connections	2
Benzene Abatement Structure, Foundation and Connections	1
<u>Chemical H2S Abatement Structure, Foundation and Connections</u>	1 <u>2</u>
NCG Removal System Structure, Foundation and Connections	1
Steam Vent Tank Foundation and Connections	4
Waste Water Collection System Foundation and Connections	1
Main Injection Pumps Foundation and Connections	4
Fire Protection System	1
Injection Booster Pump Foundation and Connections	4
Brine Pond Pumps Foundation and Connections	2
Generator Breakers Foundation and Connections	3
Transformer Breakers Foundation and Connections	3
Wellhead Separators Foundation and Connections	4
SP Crystallizers Foundation and Connections	4
LP Crystallizers Foundation and Connections	4
Atmospheric Flash Tanks Foundation and Connections	4
Dilution Water Heater/Pumps Foundation and Connections <u>Organic Rankine Cycle Foundation and Connections</u>	2 <u>1</u>
Scrubbers Foundation and Connections	6
Demisters Foundation and Connections	6
Primary Clarifiers Foundation and Connections	2 <u>1</u>
Secondary Clarifiers Foundation and Connections	2 <u>1</u>
Vacuum System Foundation and Connections	4
Electric Motor Driven Fire Pump Foundation and Connections	1
Diesel Engine Fire Pump Foundation and Connections	1
Firewater Storage Tank Foundation and Connections	1
Compressed Air System Foundation and Connections	2
<u>Isopentane Tank Foundation and Connections</u>	<u>2</u>
<u>Tower Brom Tanks Foundation and Connections</u>	<u>1</u>
<u>Hydrogen Peroxide Tank Foundation and Connections</u>	<u>1</u>
HCL Tank Foundation and Connections	1
Emergency Relief Tanks Structure, Foundation and Connections	4
Seed Pumps Foundation and Connections	4
Control Room Structure, Foundation and Connections	1
RO/Potable Water Systems	2
Drainage Systems (including sanitary drain and waste)	1 Lot
High Pressure and Large Diameter Piping and Pipe Racks	1 Lot
HVAC and Refrigeration Systems	1 Lot
Temperature Control and Ventilation Systems (including water and sewer connections)	1 Lot

Equipment/System	Quantity (Plant)
Building Energy Conservation Systems	1 Lot
Substation/Switchyard, Buses and Towers	1 Lot
Electrical Duct Banks	1 Lot

In its Petition for Amendment, CEOE requests that Noise Condition of Certification **NOISE-6** be modified as shown below in underline/strikethrough. The requested changes would reduce restrictions on project noise during plant startup, shutdown and upset, and whenever steam relief valves operate. Such easing of restrictions can be expected to increase noise impacts on sensitive receptors. Energy Commission staff does not agree with these requested changes to **NOISE-6**, and does not recommend they be incorporated in the amendment.

CONCLUSIONS

The requested changes in project design and construction will allow the project to operate more economically, and to make more effective use of the geothermal resource. Staff recommends that the Petition be granted. Staff recommends that the changes requested to Facility Design Condition of Certification **GEN-2** be included in the Amendment, but recommends that the changes requested to Noise Condition of Certification **NOISE-6** not be included. This recommendation is based on the following:

1. I have analyzed the situation from the standpoint of Efficiency, Reliability, Facility Design, and Noise and Vibration, and conclude there will be no new or additional significant environmental impacts associated with this action.
2. I conclude that the amendment is based on new information that was not available during the licensing proceedings.
3. I conclude that the proposed modification retains the intent of the original Commission Decision and Conditions of Certification.

SALTON SEA GEOTHERMAL UNIT #6 (02-AFC-2C)
PETITION TO ADD A BINARY-CYCLE TURBINE AND INCREASE
GENERATION
HAZARDOUS MATERIALS ANALYSIS
MARCH 3, 2005
RICK TYLER

REQUEST

CE Obsidian Energy (CEOE) proposes to add supplemental generating capacity to Unit 6 by adding an additional power cycle using isopentane as a working fluid

ANALYSIS

The addition of the isopentane based power generating cycle will necessitate the storage and handling of about 18,500 gallons of isopentane at the site. Isopentane is a hazardous material that poses a risk of both fire and explosion. These risks are enhanced by the heating of the isopentane to a vapor state in the power generating cycle. The handling and use of isopentane poses the only new potentially significant risk associated with this amendment.

The Salton Sea facility is in a very remote location that mitigates to a large degree the potential for impacts to the public that could result from an accidental release of isopentane. The project owner's analysis utilizing a very conservative model, suggests that a worst case explosion would not produce impacts at any public receptor or residence. The proposed amendments will require the preparation of Risk Management Plans, Process Safety management Plans and compliance with California's Accidental Release Program. These plans will provide additional reduction of accidental release risks and will be prepared and submitted to applicable regulatory agencies prior to construction or delivery of Isopentane to the facility. Perhaps the greatest potential issue regarding this amendment is the potential implications that the additional Isopentane cycle will have on fire protection systems at the facility. Staff requested additional clarification regarding fire protection and determined that the new cycle is designed with integral fire protection systems that are extensive. In addition the fire protection plan will be amended and sent to the local fire department for review. With timely submittal and acceptance of these plans by the applicable regulatory agencies this facility will pose no significant risks to public health and will remain in compliance with applicable LORS.

LAWS, ORDINANCES, REGULATION, AND STANDARDS

There are no new LORS associated with this amendment not considered in staff's original analysis of the Salton Sea Unit 6 Geothermal project.

I. Recommended changes to Existing Conditions of Certification

Deleted language is shown in ~~strikethrough~~, new text is shown in bold and double underline.

HAZ-2 The project owner shall provide a Risk Management Plan ~~(RMP)~~ **and Process Safety Management Plan** (if required by ~~local regulatory body~~) to appropriate local administering agencies and the CPM for review at the time the RMP is first submitted to the U.S. Environmental Protection Agency (EPA). A Hazardous Materials Business Plan ~~(HMBP)~~, which shall include the proposed building chemical inventory as per the ~~UFC~~ **Uniform Fire Code** shall also be submitted to appropriate local administering agencies for review and to the CPM for review and approval prior to construction of hazardous materials storage and containment structures. The project owner shall include all recommendations of the local administering agencies and the CPM in the final HMBP. A copy of the final RMP, including all comments, shall be provided to appropriate local administering agencies and the CPM once it receives EPA approval.

Verification: At least 30 days prior to the commencement of construction of hazardous materials storage and containment structures, the project owner shall provide the final plans (RMP, **Process Safety Management Plan**, and HMBP) listed above to the CPM for approval.

**SALTON SEA GEOTHERMAL UNIT #6 (02-AFC-2C)
PETITION TO ADD A BINARY-CYCLE TURBINE AND INCREASE
GENERATION
LAND USE ANALYSIS
David Flores
March 2005**

REQUEST

CE Obsidian Energy, LCC (CEOE) requests to amend the Salton Sea Unit 6 project to:

- Add one geothermal production well and one brine reinjection well with associated piping;
- Increase geothermal brine flow approximately 18 percent to produce an additional 15 MW of electrical power;
- Add an Organic Rankine Cycle (ORC) turbine generator to increase electrical power output an additional 10 MW;
- Eliminate redundant clarifier trains and vacuum belt filters;
- Increase cooling tower size and change its configuration; and
- Add four, 40-foot emergency steam relief stacks to the atmospheric flash tanks.

BACKGROUND

The Salton Sea Unit 6 project was certified by the Energy Commission as a 185 MW geothermal power plant employing a triple flash, three-pressure steam turbine generator cycle. This technology represented the most efficient generating technology yet applied to this geothermal resource. When the project owner solicited bids from engineering /construction firms, the proposals received recommended certain improvements to the project that would increase generation efficiency and reduce per-kilowatt capital cost. Accordingly, CEOE seeks to amend the project certification to allow incorporation of these improvements.

LAWS, ORDINANCES, REGULATION, AND STANDARDS

At the time of certification, LORS applicable to Land Use were identified in Staff's Final Staff Assessment. These LORS will continue to apply to the amended project, and no new LORS have been identified. Additionally, the proposed design changes will continue to comply with the Imperial's County's General Plan's Land and Geothermal and Transmission Element.

ANALYSIS

Staff's previous analysis of the original proposal for the Salton Sea Unit 6 project remains valid and indicates the project will not cause a significant land use impact. Although the project description has changed by the addition of 20 acres to the project

footprint, staff took into consideration the 160-acre parcel which the project will be situated. The 160-acre parcel is not within a Williamson Act contract or within a Farmland Security Zone. Because the additional 20 acres was not included in the Imperial County's Conditional Use Permit (CUP), a minor modification to the CUP will be required to reflect the increase in the number of production and injection wells. Proposed condition of certification LAND-8 requires that the applicant submit the necessary documentation to Imperial County for the Minor Modification to the Conditional Use Permit, and appropriate copies be sent to the CPM for review and approval.

PROPOSED MITIGATION MEASURES AND NEW CONDITION OF CERTIFICATION

The original project included seven Land Use Conditions of Certification. These conditions will provide adequate assurance that the modified project will comply with the local LORS. With the addition of 20 acres to the project footprint, LAND-6 has been modified to reflect the increased the loss of prime farmland from 96 acres to 116 acres. Staff has also provided an additional condition LAND-8, which requires the applicant to provide copies to the CPM of the final decision by Imperial County for the minor modification to the Conditional Use Permit. Deleted language is shown in ~~strike through~~, new text is shown in bold and double underline.

LAND-6 The project owner shall mitigate for the loss of ~~96~~ **116** acres at a one to one ratio for the conversion of prime farmland as classified by the California Department of Conservation, to a non-agricultural use, for the construction of the power generation facility.

Verification: The project owner will provide a mitigation fee payment (payment to be determined) to an Imperial County agricultural land trust within 30 days following the construction start, as set forth in a prepared Farmlands Mitigation Agreement.

The project owner shall provide in the Monthly Compliance Reports a discussion of any land and/or easements purchased in the preceding month by the trust with the mitigation fee money provided, and the provisions to guarantee that the land managed by the trust will be farmed in perpetuity. This discussion must include the schedule for purchasing ~~96~~ **116** acres of prime farmland and/or easements within five years of start of construction as compensation for the ~~96~~ **116** acres of prime farmland to be converted by the SSU6.

LAND-8 The project owner shall comply with Imperial County's Minor Modification to the Conditional Use Permit requirements for the additional 20 acres not covered by the CUP that was approved by Imperial County.

Verification: At least 30 days prior to start of construction, the project owner shall submit to the CPM, written documentation, including evidence of review and approval by Imperial County that the project conforms to all requirements of the Minor Modification to the CUP.

**SALTON SEA GEOTHERMAL UNIT #6 (02-AFC-2C)
PETITION TO ADD A BINARY-CYCLE TURBINE AND INCREASE
GENERATION
TRANSMISSION SYSTEM SAFETY AND NUISANCE ANALYSIS
OBED ODOEMELAM
FEBRUARY 2005**

REQUEST

CE Obsidian Energy, LLC requests to amend the Salton Sea Unit 6 Project to increase total generation from the approved 185 megawatts to 215 megawatts and the transmission voltage from 161 kV to 230 kV. The approved 161 kV transmission lines were designed with the capacity for the requested transmission at 230 kV.

BACKGROUND

The Salton Sea Unit 6 Project was certified by the Energy Commission as a 185 MW geothermal power plant to transmit the generated power at 161 kV using transmission lines with a design capacity of 230 kV. This was intended to allow for future higher-voltage (230 kV) transmission without modifications to the line. The present request for 230 kV transmission would be in keeping with the applicant's original permitting approach.

LAWS, ORDINANCES, REGULATION, AND STANDARDS

At the time of certification, LORS applicable to Transmission Line Safety and Nuisance were identified in staff's Final Staff Assessment as applicable to transmission at 161 kV and 230 kV. These LORS will continue to apply to the amended project.

ANALYSIS

The applicant's transmission line permitting approach was to design the project's transmission lines to allow for the initial transmission at 161 kV and later transmission at 230 kV as proposed to accommodate the generation increases. The permitted design for 161 kV transmission would be applicable at 230 kV as mitigation against the field and non-field impacts of concern to staff. No modifications would be necessary.

MITIGATION MEASURES AND CONDITIONS

The original project certification included five Conditions of Certification related to Transmission Line Safety and Nuisance. With one modification to TLSN-1 as shown below, the conditions will provide adequate assurance that the proposed higher-voltage transmission will minimize the impacts of concern (aviation safety, interference with radio-frequency communication, audible noise, fire hazards, hazardous shocks,

nuisance shocks and electric and magnetic field exposure) to within levels associated with area lines in the 161kV -230 kV voltage class, as identified by California Public Utilities Commission policy.

RECOMMENDED CHANGES TO EXISTING CONDITIONS OF CERTIFICATION

Deleted language is shown in ~~strikethrough~~, new text is shown in bold and double underline.

TLSN-1 The project owner shall ensure that the proposed ~~161~~**230** kV lines are designed and constructed according to the requirements of CPUC's GO-95, GO-52, the applicable sections of Title 8, California Code of Regulations section 2700 et seq., and IID's EMF reduction guidelines arising from CPUC Decision 93-11-013.

Verification: Thirty days before starting construction of the SSU6 transmission lines or related structures and facilities, the project owner shall submit to the Energy Commission's Compliance Project Manager (CPM) a letter signed by a California registered electrical engineer affirming compliance with this requirement.

**SALTON SEA GEOTHERMAL UNIT #6 (02-AFC-2C)
PETITION TO ADD A BINARY-CYCLE TURBINE AND INCREASE
GENERATION
TRANSMISSION SYSTEM ENGINEERING ANALYSIS
SUDATH ARACHCHIGE
MARCH 2005**

ANALYSIS

Staff has reviewed the interconnection study to analyze system reliability impacts determine conformance with Laws, Ordinances Regulations and Standards (LORS) and to be confident of identifying the interconnection facilities and any new and/or modified downstream facilities necessary to support the power increase of 30MW above the existing 185MW maximum interconnection capacity. The net output of 200MW generation was considered for System Impact Study (SIS) purposes and demonstrated that the generation will be consumed within the Imperial Irrigation District (IID) system under the study scenarios of 2008 summer peak and spring off peak system conditions. The Study was conducted by K.R. Saline and Associates as requested by the generation developer, CE Obsidian Energy (Cal Energy).

The proposed Salton Sea Unit 6 Geothermal Project (SSU6) will consist of one steam turbine generator with a nominal output of approximately 215MVA. Total generation rated output was specified in the interconnection study as 215MW with an auxiliary plant load of 15MW, and a net generating capacity of 200MW. The expected on-line date of the project is the summer of 2008.

Cal Energy proposes to connect SSU6 into the IID transmission system via two new 230kV lines as proposed in the previous AFC process. One of the proposed lines, a 16 mile 230kV single circuit, would connect to the IID 230kV bus at the new Bannister Substation. The other 15 mile 230kV single circuit line would directly connect to the IID existing Midway Substation. The existing 161kV "L" line would loop in and out through the 161kV bus at the IID Banister Substation. The proposed 230/161kV step down transformer would interconnect 230kV and 161 kV buses of the IID Banister Substation. The generator output would be step up through a dedicated 16/230kV, 260MVA transformer which would connect to the proposed 230kV lines via a ring bus breaker configuration. This configuration is the same as approved by the Commission in the AFC process except the two lines are operated at 230 kV rather than 161kV. (System Impact study submitted to the California Energy Commission, March 2005)

SYSTEM IMPACT STUDY

The power flow studies evaluated two dispatch scenarios of SSU6 generation under peak and off peak conditions for adjusted 2008 Base Cases. The import generation from WAPA and Arizona to the IID system was replaced with SSU6 generation for SIS

study purposes. The studies included normal system conditions and a selected list of relevant single and multiple outages to identify thermal overloads and congestion issues.

SYSTEM IMPACT STUDY RESULTS AND MITIGATION

The power flow analysis showed that the incremental loading on IID facilities was found to be less than 2% with the addition of the project under N-1 conditions. For the existing N-2 outages on the IID system that require a Remedial Action Scheme (RAS) to trip existing geothermal generation along IID's collector system, this analysis shows that additional RAS tripping may be required with the addition of the USS6 project. Additionally, the SSU6 project was also found to decrease the flow on the Blythe-Niland "F" 161kV and Imperial Valley-El Centro "S" 230kV lines.

CONFORMANCE WITH LORS

The LORS applicable to the licensed power plant switchyard and outlet transmission line are listed in the SSU6 Commission Decision (02-AFC-2, TSE Section, page 215). Based on the results of the SIS staff concludes that system reliability LORS would be met. Additionally, the two outlet circuits which are now to be operated at 230 kV rather than 161 kV were previously analyzed for operation at 161 kV or 230 kV; hence the analysis for conformance with LORS will not be changed.

CONCLUSIONS AND RECOMMENDATIONS

The Salton Sea Unit 6 generation project will have some marginal impact in the system, but the selected mitigation measures are appropriate to offset the impacts. There will no downstream upgrades in the IID system due to the addition of SSU6. Staff considers the study and mitigation measures acceptable.

The mitigation measures will assure conformance with LORS assuming compliance with the proposed modified conditions of certification.

CONDITIONS OF CERTIFICATION

All previous conditions of certification for the project continue to be accurate except TSE-5. In TSE-5 the indication that the line voltage would be 161 kV must be changed to reflect the new proposal which uses a 230 kV voltage. With that change TSE-5 would read as follows. Deleted language is shown in ~~strike through~~, new text is shown in bold and double **underline**.

TSE-5 The project owner shall ensure that the design, construction and operation of the proposed transmission facilities will conform to all applicable LORS, including the requirements listed below. The project owner shall submit the required number of copies of the design drawings and calculations as determined by the CBO.

- (a) The SSU6 will be interconnected to IID grid via two ~~230/464kV~~ single circuits. One of the proposed interconnections would be a 16-mile single **230 kV** circuit connected to the **230 kV bus** L-line at ~~the~~ Bannister switching **Substation**. The new Bannister switching **Substation** ~~will utilize shall be~~ a **230 kV** ~~three breaker~~ ring bus configuration. The other interconnection would be a 15-mile **230 kV** single circuit ~~464kV L-line~~ connected at the Midway substation.
- (b) The power plant switchyard and outlet line shall meet or exceed the electrical, mechanical, civil and structural requirements of CPUC General Order 95 or National Electric Safety Code (NESC), Title 8 of the California Code and Regulations (Title 8), Articles 35, 36 and 37 of the "High Voltage Electric Safety Orders", Cal-ISO standards, National Electric Code (NEC) and related industry standards.
- (c) Breakers and busses in the power plan switchyard and other switchyards, where applicable, shall be sized to comply with a short-circuit analysis.
- (d) Outlet line crossings and line parallels with transmission and distribution facilities shall be coordinated with the transmission line owner and comply with the owner's standards.
- (e) The project conductors shall be sized to accommodate the full output from the project.
- (f) Termination facilities shall comply with applicable ~~SGD&E~~ **IID** interconnection standards.

The project owner shall provide to the CPM:

The final Detailed Facility Study (DFS) including a description of facility upgrades, operational mitigation measures, and/or Special Protection System (SPS) sequencing and timing if applicable,
Executed project owner and IID Facility Interconnection Agreement.

Verification: At least 60 days prior to the start of construction of transmission facilities (or a lesser number of days mutually agree to by the project owner and CBO, the project owner shall submit to the CBO for approval:

1. Design drawings, specifications and calculations conforming with CPUC General Order 95 or NESC, Title 8, Articles 35, 36 and 37 of the "High Voltage Electric Safety Orders", NEC, applicable interconnection standards and related industry standards, for the poles/towers, foundations, anchor bolts, conductors, grounding systems and major switchyard equipment.
2. For each element of the transmission facilities identified above, the submittal package to the CBO shall contain the design criteria, a discussion of the calculation method(s), a sample calculation based on "worst case conditions"¹ and a statement signed and sealed by the registered engineer in responsible charge, or other acceptable alternative verification, that the transmission element(s) will conform with CPUC General Order 95 or NESC, Title 8, California Code of Regulations, Articles

¹ Worst case conditions for the foundations would include for instance, a dead-end or angle pole.

35, 36 and 37 of the, “High Voltage Electric Safety Orders”, NEC, applicable interconnection standards, and related industry standards.

3. Electrical one-line diagrams signed and sealed by the registered professional electrical engineer in responsible charge, a route map, and an engineering description of equipment and the configurations covered by requirements **TSE-5** a) through f) above.
4. The final DFS, including a description of facility upgrades, operational mitigation measures, and/or SPS sequencing and timing if applicable, shall be provided concurrently to the CPM.